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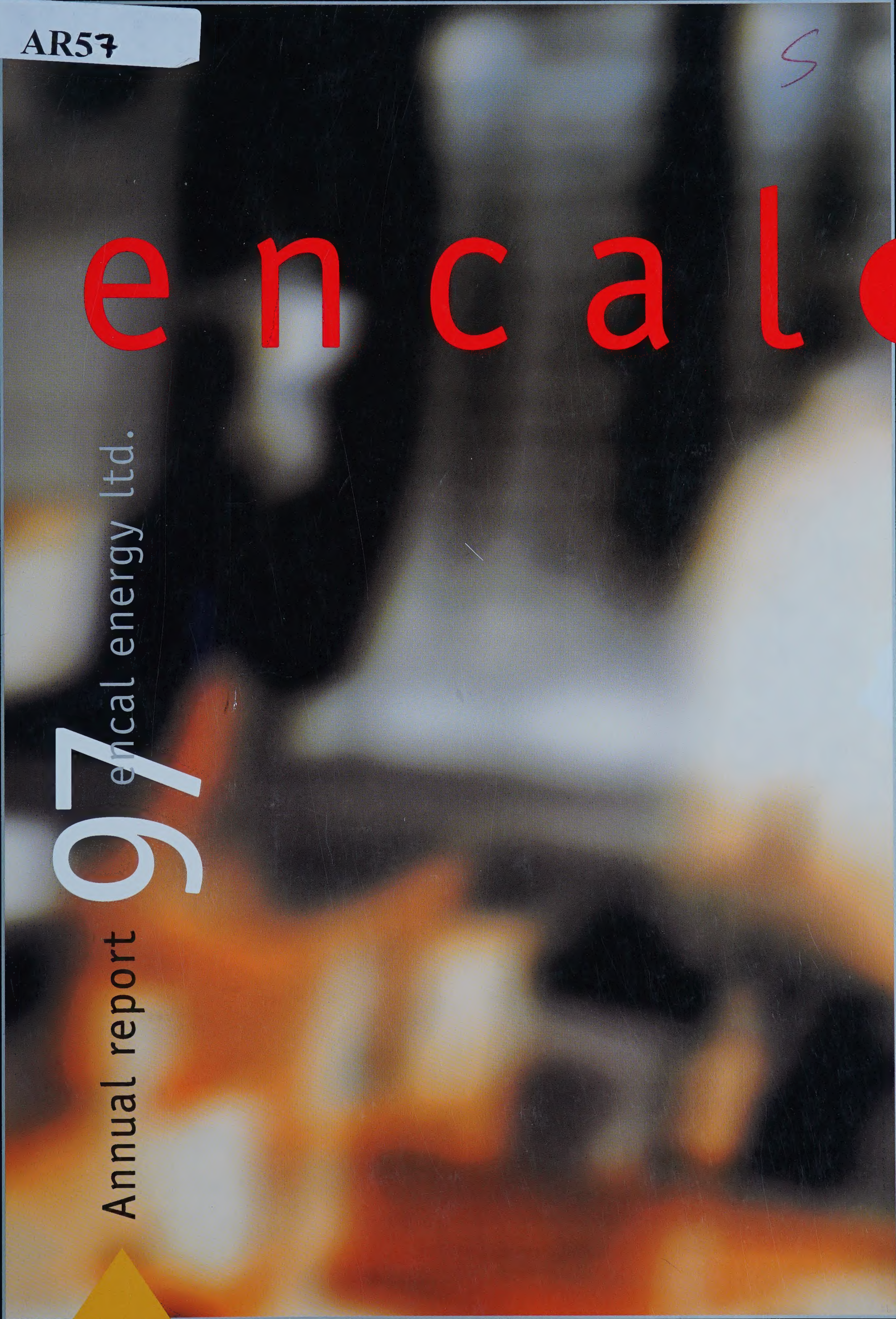


encal

Annual report 97

encal energy ltd.

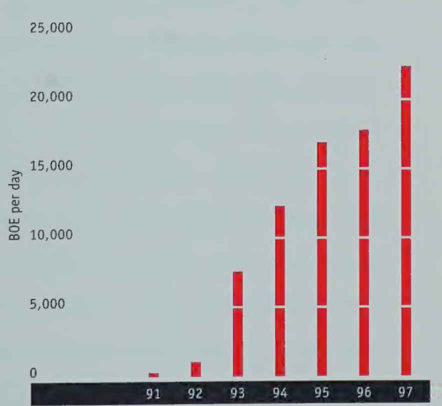
Encal Energy Ltd. is a western Canada based, oil and gas exploration and production company, with an emphasis on successfully finding and efficiently producing reserves. Encal strives to be a top performer in key industry measures: production growth, finding costs, reserve additions, operating costs and general and administrative costs. Encal Energy Ltd. is based in Calgary, Alberta and publicly trades on The Toronto Stock Exchange, symbol ENL and the New York Stock Exchange under the symbol ECA.

1 #68

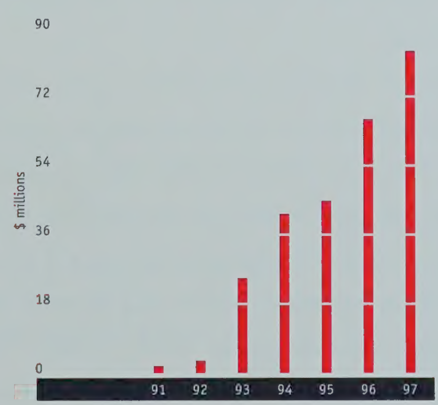
($ thousands except per share amounts)	1997	1996	% Increase
Financial			
Petroleum and Natural Gas Sales	167,846	124,294	35
Funds From Operations	84,101	66,195	27
Per Common Share - Basic	0.81	0.64	27
- Fully Diluted	0.77	0.62	24
Net Earnings	13,031	11,518	13
Per Common Share - Basic	0.12	0.11	9
- Fully Diluted	0.12	0.11	9
Net Capital Expenditures	157,558	109,280	44
Long Term Debt	143,414	64,046	124
Operating			
Production			
- Crude Oil (bbls/d)	6,931	5,432	28
- Natural Gas (mcf/d)	130,197	105,713	23
- Natural Gas Liquids (bbls/d)	2,485	1,800	38
- Total (BOE/d)	22,436	17,803	26
Reserves			
Crude Oil and NGLs (mbbls)			
- Proven	28,488	19,748	44
- Proven plus Probable	40,912	28,680	43
Natural Gas (bcf)			
- Proven	410	351	17
- Proven plus Probable	605	520	16

In 1997 production increased by 26%

and cash flow was up by 27%



Annual production growth



Annual cash flow growth

1997 was Encal's most successful year to date

president's

The year 1997 proved to be Encal's most successful to date. Financial and operating results continue to demonstrate impressive growth, driven by our internally generated exploration program and supplemented by opportune acquisitions. We expect this trend to continue.

The momentum established by our exploration program has provided strong production, reserve and cash flow growth per share for our shareholders during 1997. The advantage of our internal program was never more evident than during the past year when industry acquisition costs rose beyond a level permitting sustainable economic growth.

Perhaps the highlight of 1997 for Encal was the strong production growth achieved. Year over year increases totaled 26 percent while year end exit rates exceeded our original target by over 1,000 barrels of oil equivalent per day. Over the past eight quarters Encal has added an average of 1,000 barrels of oil equivalent per day per quarter. We look forward to continuing this record into 1998.

In terms of reserve replacement costs, Encal improved its performance during the year in spite of escalating industry service costs and increased competition. Full cycle finding and development costs were $6.92 per barrel of oil equivalent proven and $5.46 per barrel of oil equivalent proven plus probable on record capital expenditures of $158 million. The Company replaced its annual production by a factor of 3.5 times. Encal's cost of new production additions was also impressive having brought over 11,400 barrels of oil equivalent on production at a cost of $13,797 per barrel of oil equivalent per day beating 1996 performance of $15,292 per barrel of oil equivalent per day.

The combination of efficient reserve and production replacement has again resulted in a year over year increase in net asset value per share of more than 17 percent while the year's activity has lowered our historical depletion rate and thereby improved profitability.

Over the past four years Encal has reduced the number of core areas by 50 percent while production has almost doubled. The program has focussed on light crude oil and liquid-rich natural gas in the Fort St. John area of northeastern British Columbia and the west central area of Alberta. This focus on quality assets in areas where Encal has a proven track record of consistent economical growth is our continuing advantage. Acquisition, as in the past, will only be pursued when core areas can be enhanced and Encal can grow the acquired assets at a pace at least equal to our historic base growth.

Another key factor in share value has been our conservative approach to funding our programs. Capital expenditures in excess of cash flow since 1993 have been funded from the disposition of non core assets as well as increased balance sheet leverage. At year end our total debt to cash flow ratio was 1.8:1. This ratio is

message

not expected to exceed 2.0:1 by year end 1998. Capital expenditures for 1998 will be similar to 1997 with approximately $130 million dedicated to the base program. The remainder, $30 million, has been provided for and may be invested in discretionary expenditures including acquisitions and higher impact exploration.

At the time of writing this Annual Report, the price of crude oil is under pressure from a number of supply and demand issues. This is not the first time Encal has experienced this phenomenon and it likely will not be the last. The best defense we have is low replacement, operating and administrative costs and for this reason we have continued to focus on these controllable items all of which showed improvement during 1997. Natural gas prices although softer during the 1997/1998 heating season due to the El Niño effect, now appear to have considerable upside. The combination of expanding North American demand and increased export pipeline capacity bodes well for Western Canadian gas producers. Encal has positioned itself well with an asset mix of 60 percent natural gas, 10 percent natural gas liquids and 30 percent light to medium crude oil. Our focus remains on per share growth sourced from core areas where our track record speaks for itself.

This year's annual report to shareholders has been designed to communicate Encal's performance and business strategy in a concise manner. The first pages provide a snapshot of Encal's highlights while the expanded Management Discussion and Analysis section provides detailed disclosure of our financial and operating results.

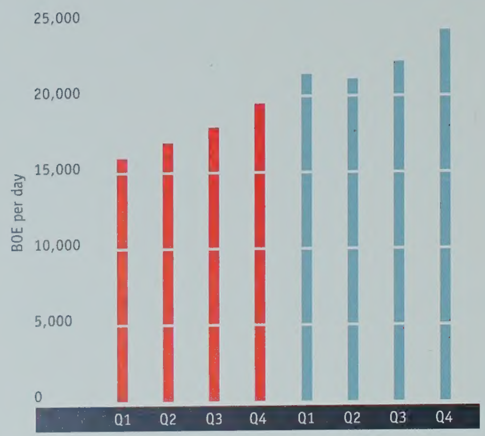
During the year, Mr. Peter Lougheed, P.C., C.C., Q.C., retired as a member of our Board of Directors. Mr. Lougheed helped guide Encal and predecessor companies since 1985. On behalf of the employees and Board of Directors we thank you for your strong support and guidance.

I would like to conclude this report to shareholders by recognizing the contribution of our staff. We believe that Encal has one of the brightest and hardest working group of employees in the industry. From our field operations to our Calgary staff, 1997 proved to be a most gratifying and successful year. To all employees, on behalf of the shareholders and the Board of Directors, thank you for your efforts and positive contribution. Together we look forward to the future.

D D Johnson

David D. Johnson
President and
Chief Executive Officer

March 10, 1998



Two years of steady production growth

	Capital	Net Production Additions	Production Additions Cost
	($ thousands)	(BOE/d)	($/BOE/d)
1996	109,280	7,146	15,292
1997	157,558	11,420	13,797
Total	266,838	18,566	14,372

Cost of net production additions

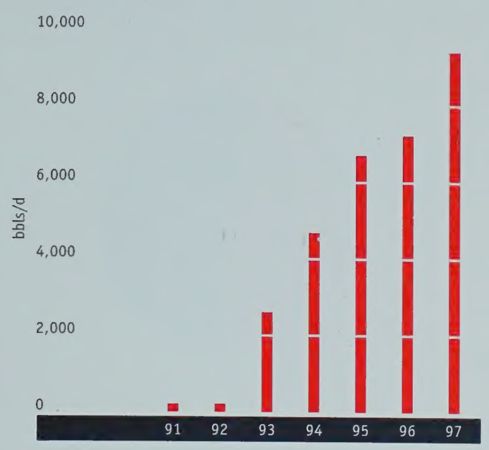
An active drilling year contributed to record production gains

production

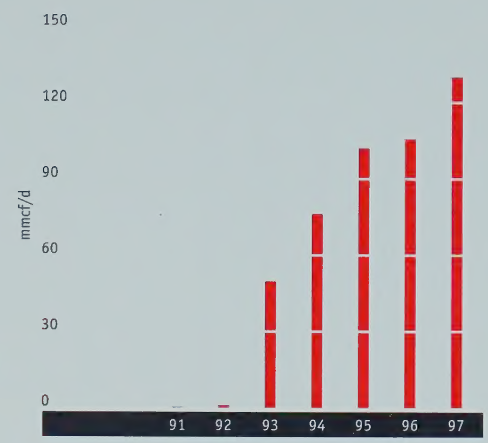
Growing, independent production companies face two significant realities in the western Canadian oilpatch. The region is mature with most of the major, high quality discoveries already made and there is ever-tightening competition which increases the cost of doing business. Encal's approach to successfully grow in this setting is to ensure reinvestment is concentrated in areas where the Company can dominate and to continually re-evaluate opportunity so that resources are dedicated where they will have a meaningful impact. The strategies are working and 1997 proved to be another strong year for production growth. On average, year over year production increased by 26 percent culminating in an exit rate well ahead of target.

A 30 percent growth in liquids production was achieved during 1997. Crude oil and natural gas liquids production averaged over 9,400 barrels per day for the entire year with fourth quarter volumes exceeding 11,000 barrels per day. In northeastern British Columbia Encal added 2,800 barrels per day of Triassic oil, resulting from the successful drilling programs in the Rigel and Oak areas plus the acquisition of the Beatton River property. Encal's eastern Alberta shallow oil activities at Jenner, Consort and Cadogan added over 2,100 barrels per day of oil. Continued focus on liquid-rich gas plays in the Modeste Creek, Columbia, Cutbank and Redeye areas added 800 barrels per day of NGLs during the year.

Natural gas production also showed strength in 1997, increasing the average by almost 25 million cubic feet per day or 23 percent year over year to 130 million cubic feet per day. Ongoing exploitation in the Cecil and North Pine areas, the acquisition and drilling of the Bulrush property combined with the winter drilling activities in the Redeye area resulted in 27 million cubic feet per day of incremental gas production. In Alberta, gas drilling and acquisitions targeted Missisippian Formations in the Innisfail, Wilson Creek, Modeste and Cherhill areas. Gas production additions during the year from these areas totaled 13 million cubic feet per day during 1997. The Columbia, Minehead and Ferrier areas in western Alberta are long reserve life, high liquid



Crude oil production



Natural gas production

growth

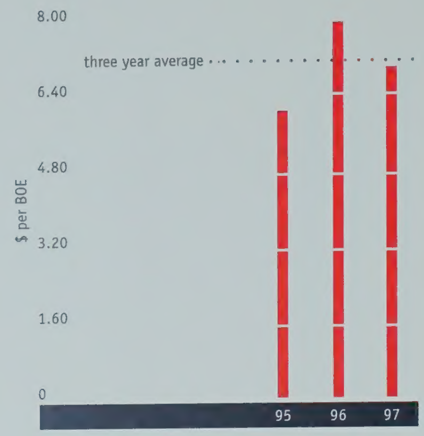
content plays for the Company. Area activities in 1997 increased production by approximately five million cubic feet per day and 200 barrels per day of NGLs.

The eight quarters of consistent growth reflect Encal's ability to generate an increasing number of quality investment opportunities. Our program is made up of the opportunities that will have the greatest impact on the dual objectives of steady cash flow growth and long-term reserve additions.

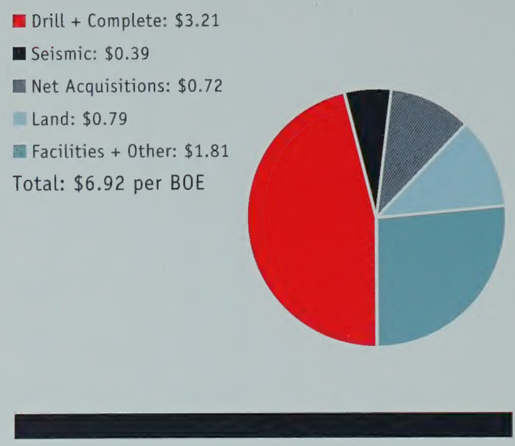
During 1998, investors can expect Encal to continue with our established strategy and grow annual base production by 20 percent. The Company will continue to improve operating and reserve replacement efficiencies and pursue acquisitions that enhance the Company's core area dominance and facility control.

We've achieved year over year growth

26%



Proven finding & development cost



1997 Proven finding & development cost components

At Encal, we recognize that low finding and development costs

finding & deve

Over the past several years, industry finding and development costs in the Western Canadian Sedimentary Basin have risen steadily, spurred upwards by intense competition for land rights, higher drilling and equipment costs, an abundance of investment capital, plus diminishing sizes of economic conventional discoveries. Our challenge is to develop a fresh approach to finding and development that encourages an openness to new ideas and technologies while maintaining a business focus.

Encal has implemented three key initiatives that offer the potential to yield substantial cost reductions and deliver a finding and development record that will differentiate the Company from its peers.

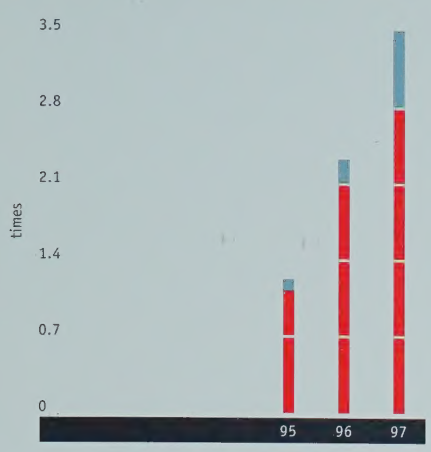
Prescribed Activity Focus

Encal devotes at least 70 percent of its time and budget to exploitation and development activities on projects where the Company has a demonstrable operational advantage and experience. Projects such as Redeye and Rigel in British Columbia, plus Wilson Creek/Innisfail, and Columbia in Alberta, prove the effectiveness of this strategy. In 1997, these four properties contributed 60 percent of the proven discoveries and extensions, at an average onstream cost of less than $3.40 per BOE.

Use of Innovative Technologies

During 1997, the Company entered into two exclusive-use agreements for innovative exploration technologies. One agreement involves the use of Stress Field Detection (SFD) technology. Encal is using SFD technology as a wide-area, exploration reconnaissance tool. Encal holds certain exclusive-use rights to this technology in western Canada.

The Company's second agreement involves seismic analysis technology referred to as Energy Attributes Analysis. This technology offers the potential to identify high-quality reservoirs within productive trends that have otherwise proven difficult to evaluate using established geophysical techniques. Encal holds exclusive-use rights to this technology in specified



Reserve replacement ratio

Proven Proven plus probable

opment cost

are key to creating an attractive and sustainable earnings record.

areas of the west central Alberta and British Columbia operating regions.

Undeveloped Land Initiatives

Approximately 30 percent of Encal's activities are allocated to on-trend exploration for analogy pools and high-impact exploration. These initiatives typically require significant up-front capital for undeveloped land. The Company will continue to minimize these capital costs through risk-adjusted bidding and targeted farm-in agreements.

During 1997, Encal maintained a disciplined approach to land expenditures, acquiring over 115,000 net acres at Crown land sales at an average price of $137 per acre, representing approximately 12 percent of the capital expenditures. The Company also entered into 11 farm-in arrangements which exposed Encal to significant land earnings on an array of core and high-impact plays. Encal will continue to pursue these strategies of land acquisition, given the premium prices for land in western Canada.

1997 Finding and Development Cost

Our program has produced tangible results. The corporate finding and development cost for 1997 declined to $6.92 per proven BOE, a reduction of $0.93 per BOE over 1996. On a proven plus probable basis, 1997 finding and development costs were $5.46 per BOE, an improvement of $1.85 per BOE over 1996.

It is important to recognize that these substantial reductions were achieved on a significantly expanded capital and drilling program. In other words, Encal spent more, found more, and found it at a more attractive rate, despite the pressures of increased supply and service costs throughout the basin. We plan further improvements for 1998.

activity

Encal's most active year, investing $158 million

During 1997, Encal continued to refine its activity focus in the two core regions of northeastern British Columbia and west central Alberta, allowing the Company to expand its dominance on several key projects.

Drilling

The Company participated in 181 gross wells, yielding 66 natural gas wells, 75 oil wells, and 40 dry holes, resulting in net drilling and completion expenditures of $73.0 million. This program included 52 exploratory tests (56 percent successful) and 129 development wells (87 percent successful). Encal operated 71 percent of the total wells drilled, 74 percent of which fell within the Company's core regions. With 53 operated wells, totalling more than 227,000 feet drilled, Encal was again the top driller in the province of British Columbia.

Exploration and Development

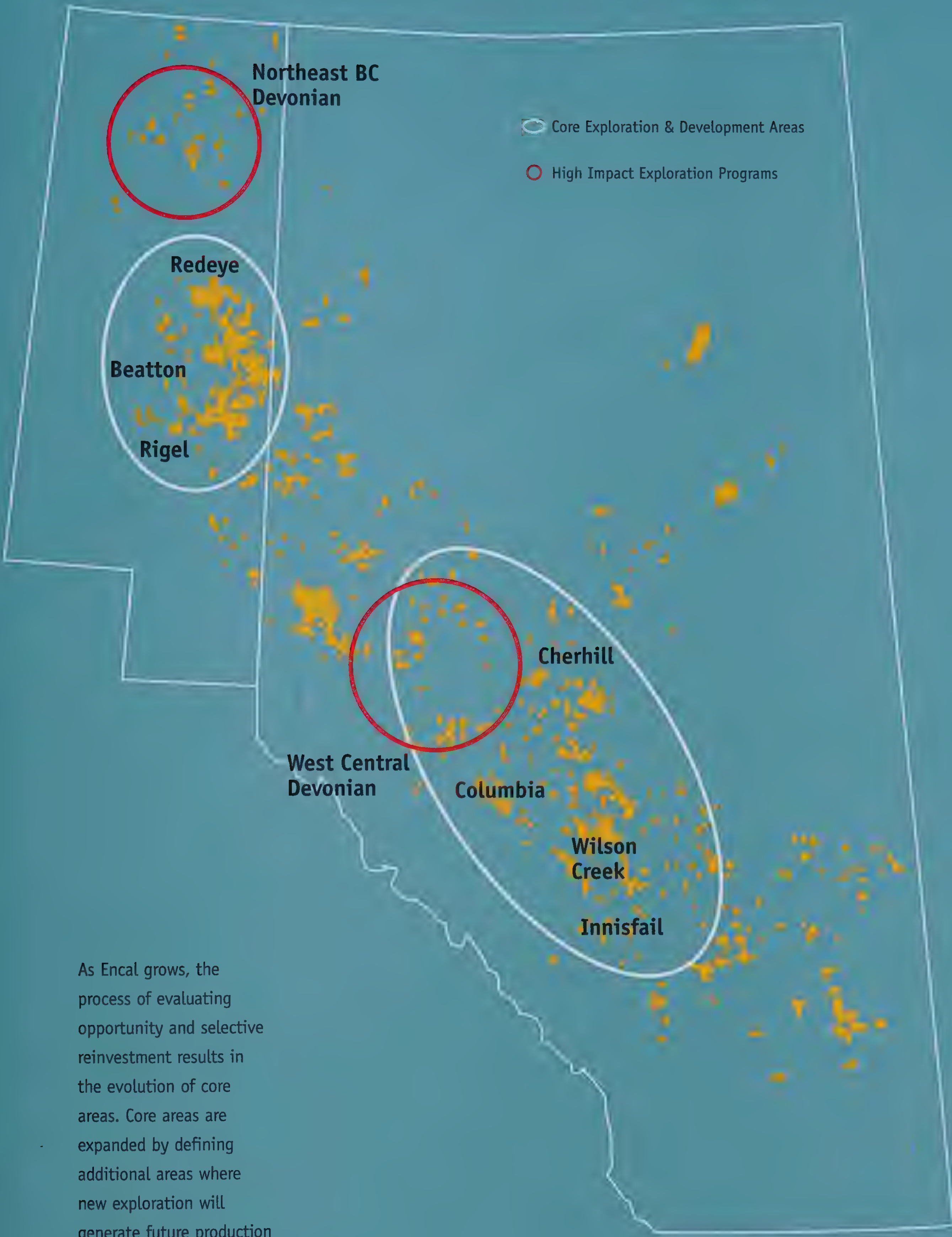
Exploratory highlights for the year included seven gas pool discoveries at Redeye, B.C., three light oil pool discoveries at Rigel, B.C., plus five gas/oil discoveries at Cherhill, Alberta. The principal development activity occurred at Rigel, B.C., and at Columbia, Jenner-Provost, and Wilson Creek in Alberta. For the first time in corporate history, Encal engaged in operated horizontal well drilling, completing a total of 14 horizontals, including 10 wells at Jenner. The Company will expand the application of its horizontal drilling program in 1998 to utilize this technique on other reservoirs throughout western Canada.

Acquisitions

Encal's 1997 property acquisition program included total purchases valued at $56.5 million, and total disposals of $40.2 million. Purchased assets included the $45.7 million Beatton-Bulrush, British Columbia package, plus selected properties at Cherhill and Ferrier, Alberta. The Company plans to enhance the value of these assets through additional exploitation efforts, improved production practices, tie-in of unconnected wells, and improved marketing arrangements.

Plant and Equipment

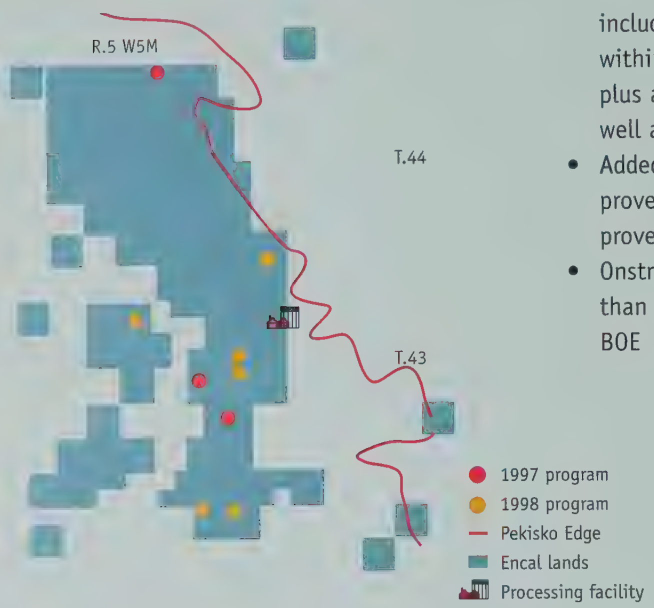
The Company spent $38.9 million on plant and equipment during 1997. Major gathering and compression systems were installed at Redeye, Cecil Lake, and Bulrush in British Columbia, and at Gordondale, Crystal and Modeste Creek in Alberta. Battery construction and water injection facilities were completed for the Cecil 'B' pool at Rigel, British Columbia. In May, Encal received conditional regulatory approval to recertify the 37 kilometer Crystal pipeline for sour service. This conversion will enhance Encal's operating position by providing transportation alternatives to area processing facilities, plus the opportunity to tie in previously unconnected gas pools along the Westerose development corridor.



As Encal grows, the process of evaluating opportunity and selective reinvestment results in the evolution of core areas. Core areas are expanded by defining additional areas where new exploration will generate future production and reserves growth.

wilson creek

Pekisko Gas and NGL Project

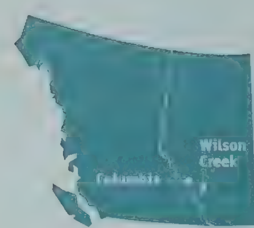


1997 Highlights

- Drilled four wells, including two horizontals within Wilson Creek unit, plus analogue horizontal well at Innisfail
- Added 1.76 million BOE proven; 2.06 million BOE proven plus probable
- Onstream cost of less than $2.05 per proven BOE

1998 Program

- Drill at least four more horizontal wells
- Continue utilizing horizontal technique on non-unit lands
- Purchase additional unit interest

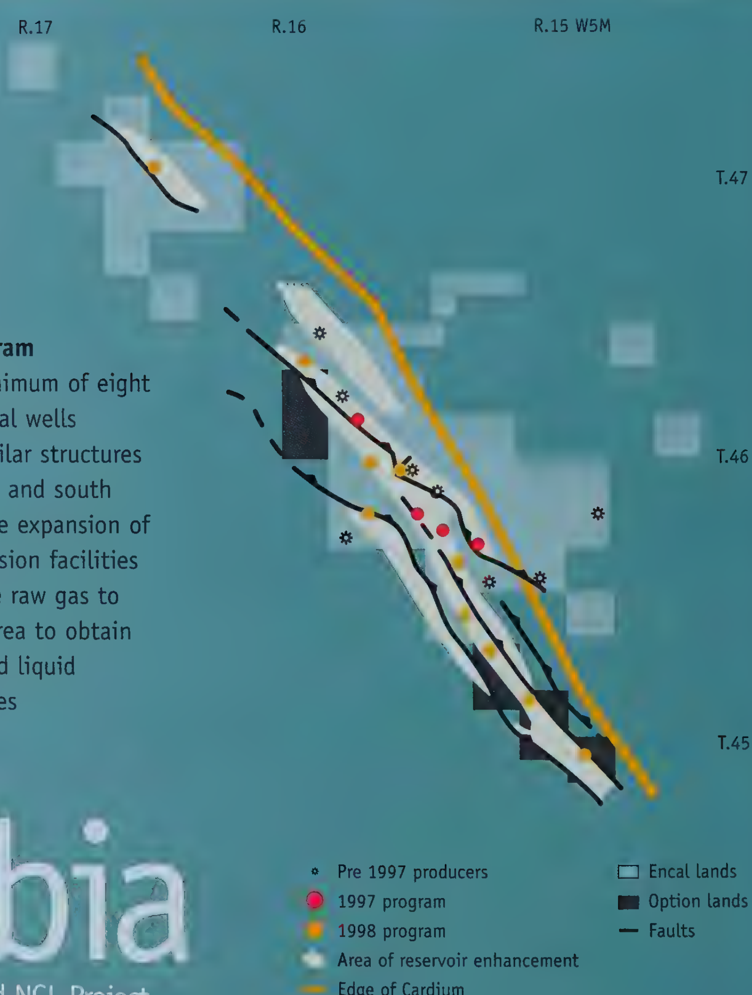


1997 Highlights

- Drilled four successful development wells
- Tied-in all four wells; commenced expansion of compression facilities
- Average liquids content of 75 Bbl/MMcf
- Achieved net sales volumes of 850 BOE/d in December
- Added 2.68 million BOE proven; 3.86 million BOE proven plus probable
- Onstream cost of less than $3.90 per proven BOE

1998 Program

- Drill minimum of eight additional wells
- Test similar structures to north and south
- Complete expansion of compression facilities
- Re-route raw gas to Edson area to obtain improved liquid recoveries



columbia

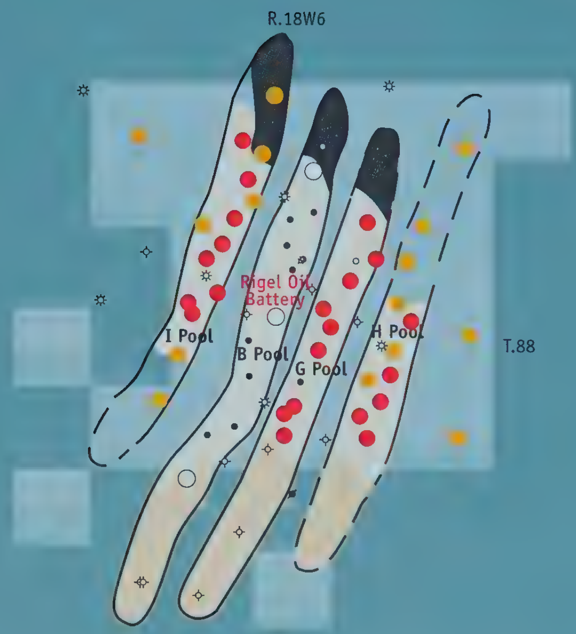
Cardium Gas and NGL Project

1997 Highlights

- Discovery of three new light oil pools
- Drilled 20 successful delineation wells
- Net production reached 2,269 bopd during December
- Added 4.10 million Bbls proven; 4.67 million Bbls proven plus probable
- Construction of central battery and waterflood facilities
- Onstream cost of less than $3.20 per proven BOE

1998 Program

- Continue development drilling in the H & I pools.
- Expand exploration efforts for new pools
- Construct water injection facilities for the G and H pools
- Test applicability of horizontal drilling



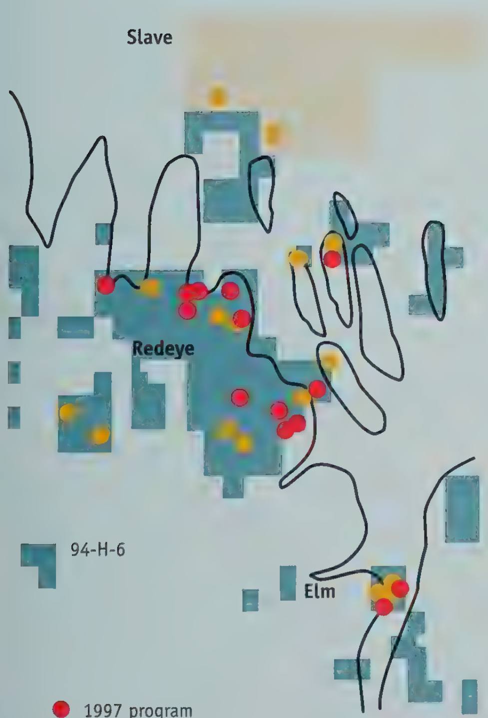
- Oil producers pre 1997
- 1997 program
- 1998 program
- Water injector wells
- Encal lands

Cecil Pools

- Gas cap
- Oil leg
- Water leg

rigel

Cecil Light Oil Project



- 1997 program
- 1998 program
- Halfway edge
- Option lands
- Encal lands

1997 Highlights

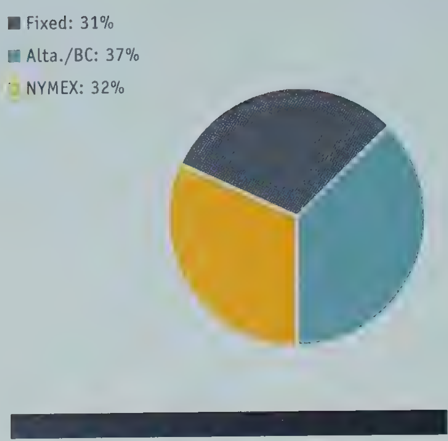
- Discovery of seven new gas pools
- Simultaneous construction of gathering and compression facilities
- Tie-in seven wells to deliver raw gas to Westcoast Highway plant
- Commenced production in June; sales reach 14 MMcf per day by December
- Added 3.32 million BOE proven; 4.34 million BOE proven plus probable
- Onstream cost of less than $3.95 per proven BOE

1998 Program

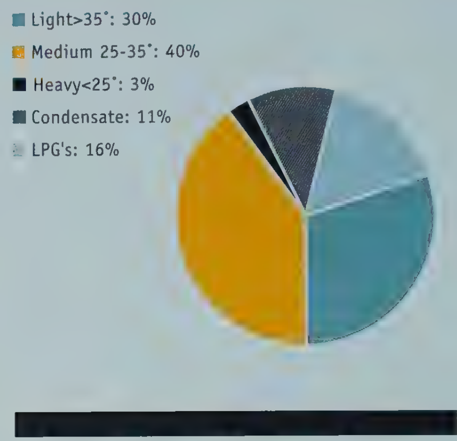
- Drill 15 additional wells
- Evaluate Elm area for Gething oil potential
- Evaluate Slave area for Paleozoic gas potential
- Increase sales volumes to 20 MMcf per day in June

redeye

Halfway and Bluesky Gas Project



Natural gas price portfolio



Liquid sales volumes

marketing

continuing to diversify markets

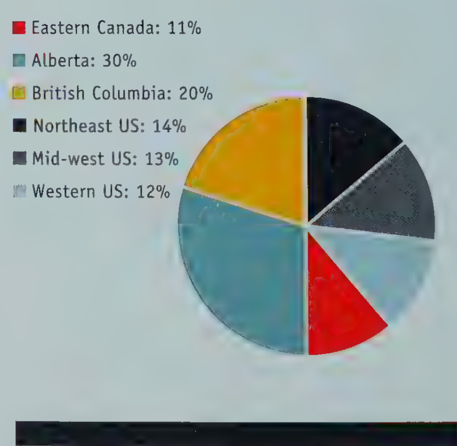
During 1997, Encal further fulfilled its marketing strategy with the continued development of a diverse sales and transportation portfolio for our products. This diversity provides Encal with a combination of control and risk management required to maximize netbacks and minimize production interruptions.

Market Diversification in 1997

Direct sales of natural gas into the Eastern Canadian market commenced with the start-up of a cogeneration power plant as well as our strategic alliance with Union Energy to provide Ontario residential customers with gas supply in an evolving deregulated environment. Export sales opportunities have been developed for Encal's growing production through the procurement of long term transportation into the New England and California markets. Additional export transportation scheduled to be on stream in the fourth quarter of 1998 will provide direct exposure to the mid-western US market.

The proposed Alliance Pipeline project is progressing towards a mid-year 2000 on-stream date and promises to provide an integration of British Columbia into the continental pipeline grid, ultimately improving Encal's British Columbia netbacks. With Encal's growing British Columbia production, the Company has been a proponent of the Alliance project since it was first proposed and has contracted for firm capacity. Alliance plans to tie into two of the plants in British Columbia where the majority of Encal's gas is processed.

Crude oil and natural gas liquid marketing activities have concentrated on netback improvements and managing pipeline curtailments. Encal has successfully consolidated sales volumes into agreements that provide price premiums. Light to medium oil and condensate make up over 80 percent of Encal's liquid production stream; these lighter products continue to attract higher prices. Increased condensate production has provided a strong revenue stream for the Company as a supplier of diluent for heavy oil producers.

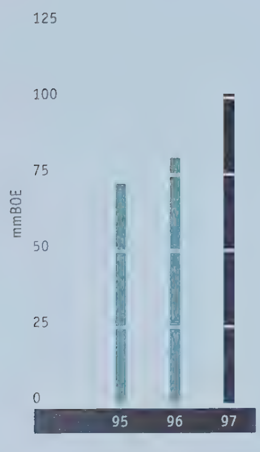


Natural gas contract portfolio

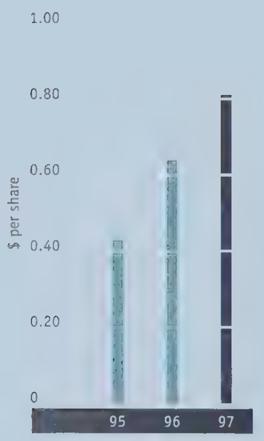
Management's Discussion and Analysis

results

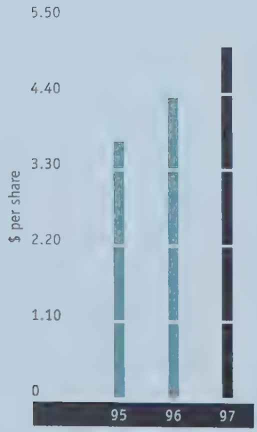
MD&A



Reserves
Proven plus probable



Cash flow per share



Net asset value

For the purposes of calculating unit costs, natural gas is converted to a barrel equivalent using 10 thousand cubic feet equal to one barrel unless otherwise stated.

The following discussion and analysis should be read in conjunction with the Financial Statements.

1997 Overview

Encal has a proven record of adding cash flow and asset value per share. This growth has been accomplished through a combination of exploration and development activities and strategic acquisitions. Petroleum and natural gas sales, funds from operations and net earnings reached record amounts in 1997. Encal's strongest financial performance to date was achieved in 1997 and the Company is well positioned to achieve even stronger results in the future.

Funds from operations increased 27 percent to $84.1 million in 1997, an increase from $66.2 million in 1996. Correspondingly, funds from operations per share increased 27 percent from $0.64 per share in 1996 to $0.81 per share in 1997. This increase is primarily the result of the growth in petroleum and natural gas production and increased natural gas prices.

Encal's net capital spending increased from $109.3 million in 1996 to $157.6 million in 1997. Drilling and completion expenditures as a percentage of net capital expenditures increased from 38 percent in 1996 to 46 percent in 1997. This increased emphasis on drilling assisted in the reduction of finding and development costs for the year. Proven plus probable finding and development costs in 1997 decreased by 25 percent to $5.46 per BOE from $7.31 per BOE in 1996. Proven finding and development costs also decreased to $6.92 per BOE in 1997 compared to $7.85 per BOE in 1996.

Significant Financial Events

On June 6, 1997 Encal commenced trading its common shares on the New York Stock Exchange under the symbol "ECA". The listing on the New York Stock Exchange will promote enhanced shareholder value through improved trading efficiencies and increased liquidity and supports the Company's view that the North American equity markets are becoming borderless.

On July 11, 1997 the Company completed a US$50.0 million private placement of Senior Unsecured Notes. The proceeds were utilized to reduce outstanding bank debt. The Notes carry a 10 year term, bear interest at 7.61 percent and are repayable in equal annual payments of US$10.0 million commencing June 30, 2003. This transaction allowed the Company to term out a portion of its core debt and is a natural hedge to our US dollar denominated revenue.

Production

Crude oil sales volumes increased 28 percent to 6,931 barrels per day in 1997 compared to 5,432 barrels per day in 1996. Increases in oil production are attributable to successful exploration and development activity at Rigel, Jenner, and the purchase of the Beatton property. Encal recorded its strongest growth in the second half of the year increasing average quarterly production by 1,000 barrels per day during each of the third and fourth quarters. Oil production averaged 8,180 barrels per day in the fourth quarter of 1997; a 50 percent increase from the fourth quarter 1996 rate of 5,447 barrels per day.

Natural gas sales volumes increased 23 percent in 1997 to average 130.2 million cubic feet per day compared to 105.7 million cubic feet per day in 1996. Increases in natural gas production are attributable to successful exploration and development activity at Redeye, Cherhill, Jenner and the purchase of the Bulrush property. Natural gas sales volumes increased to an average of over 138.0 million cubic feet per day in the fourth quarter of 1997 compared to 120.3 million cubic feet per day in the fourth quarter of 1996.

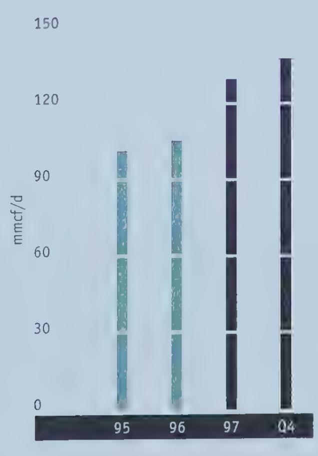
Natural gas liquid sales volumes increased 38 percent to 2,485 barrels per day in 1997 compared to 1,800 barrels per day in 1996. The increased production is attributable to liquid rich natural gas properties at Cutbank, Modeste and Redeye. Natural gas liquids production averaged 2,877 barrels per day during the fourth quarter of 1997; an increase of 39 percent over the fourth quarter 1996 production of 2,068 barrels per day.

Production Summary

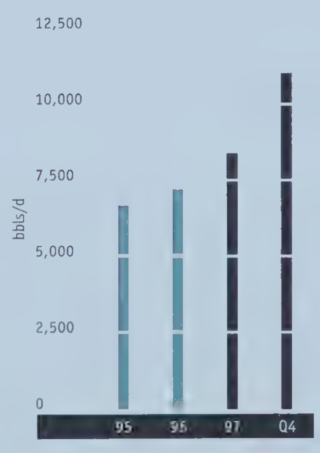
	Fourth Quarter				
	1997	1996	1997	1996	1995
Crude Oil (bbls/d)	8,180	5,447	6,931	5,432	5,236
Natural Gas (mmcf/d)	138.0	120.3	130.2	105.7	102.2
NGL (bbls/d)	2,877	2,068	2,485	1,800	1,472
Production (BOE/d)	24,855	19,546	22,436	17,803	16,928
Annual Production (mBOE)			8,189	6,516	6,179

Production Reconciliation

	Natural Gas	Crude Oil and NGL	Equivalent Production
	(mmcf/d)	(bbls/d)	(BOE/d)
Production Fourth Quarter 1996	120.3	7,515	19,546
Decline on Base Production	(25.9)	(1,465)	(4,055)
Production Additions During 1997	49.1	5,094	10,004
Declines on New 1997 Production	(9.6)	(1,095)	(2,056)
Acquisitions	11.9	1,350	2,539
Dispositions	(7.8)	(342)	(1,123)
Production Fourth Quarter 1997	138.0	11,057	24,855



Natural gas production



Crude oil & NGL production

Oil and Gas Pricing

Crude Oil Pricing

Canadian crude oil prices are referenced to an Edmonton Light Sweet price that is adjusted to West Texas Intermediate (WTI) oil prices referenced at Cushing, Oklahoma. Transportation from the wellhead to market, as well as an oil quality adjustment, are deducted to result in an average Encal field price. The 1997 average Encal field price of crude oil decreased eight percent to $24.25 per barrel, before hedging charges, compared to $26.47 in 1996. Net of hedging activities, the resulting field price was $23.38 per barrel; a three percent decrease from the 1996 price of $24.08 per barrel. Over 90 percent of Encal's 1997 crude oil production is light to medium quality which ranges between 40° to 25° API.

Crude Oil & Natural Gas Hedging

In 1997, Encal used financial instruments to hedge approximately 20 percent of crude oil and condensate sales at an average WTI price of CDN$26.66 per barrel. This resulted in a crude oil hedging charge of $1.2 million or $0.49 per barrel.

The Company has authority from the Board of Directors to use financial instruments to lock in the price on 40 percent of its 1998 crude oil and natural gas production at prices equal to or above the current year's budget. As of December 31, 1997, the Company had used financial instruments to lock in 10 percent of 1998 crude oil production at an average WTI price ranging from US$20.00 per barrel to US$21.20 per barrel. The Company recognized the potential for improvement in natural gas prices in 1998 and as of year end the majority of prices are referenced to market related indexes.

Crude Oil Pricing

($/bbl)	1997	1996	1995
WTI (US$/bbl at Cushing, Oklahoma)	20.61	22.01	18.40
Average Exchange Rate	1.3845	1.3635	1.3725
WTI (CDN$/bbl at Cushing, Oklahoma)	28.53	30.01	25.25
Less: Transportation Differential Cushing, Oklahoma to Edmonton (CDN$/bbl)	(0.87)	(0.78)	(1.21)
Edmonton Light Sweet Posting	27.66	29.23	24.04
Less: Transportation to Edmonton and Quality Adjustment	(3.41)	(2.76)	(2.68)
Encal Average Field Price before Hedging Gains (Losses)	24.25	26.47	21.36
Crude Oil Hedging Gains (Losses)	(0.49)	(2.38)	0.15
Foreign Exchange Hedging Losses	(0.38)	(0.01)	–
Encal Average Field Price after Hedging Charges (CDN$/bbl)	23.38	24.08	21.51

Foreign Exchange

The Company has authority from the Board of Directors to hedge up to 85 percent of the 1998 revenue exposed to US/Canadian dollar currency risk. The Company has entered into currency swaps to affix the Canadian/US dollar exchange rate on $127.7 million (US$93.0 million) in 1998 at a rate of 1.3734 ($0.7281 CDN) US-dollar-based revenue.

Natural Gas Pricing

In 1997, Encal had approximately 54 percent of its natural gas pricing referenced to US based market prices while another 34 percent was sold into Alberta and British Columbia. The US price is typically referenced off of the New York Mercantile Exchange ("NYMEX") at Henry Hub, Louisiana while Alberta and British Columbia prices are referenced at the Alberta Energy Company's Suffield storage field and the Nova Inventory Transfer (AECO/NIT) delivery points and Sumas, Washington. Encal's average corporate price for natural gas increased 16 percent to $1.87 per thousand cubic feet in 1997 compared to $1.61 per thousand cubic feet in 1996. During the past year, the need for additional pipeline capacity from Alberta to US markets has been reflected in the difference between natural gas prices in Alberta and those on NYMEX. The average differential was US$1.14 per mmbtu during 1997 down from US$1.53 per mmbtu during 1996. Although reduced, this gap is the result of surplus supply causing increased gas on gas competition among producers and marketers in Western Canada. The average differential in British Columbia narrowed to US$0.97 per mmbtu during 1997 from US$1.23 per mmbtu during 1996.

Natural Gas Production and Prices by Province

	1997		1996		1995	
	mmcf/d	$/mcf	mmcf/d	$/mcf	mmcf/d	$/mcf
Alberta	95.6	1.98	92.4	1.70	87.5	1.35
British Columbia	34.6	1.59	13.3	0.97	14.7	1.00
Total production and average sales price	130.2	1.87	105.7	1.61	102.2	1.30

Alberta Natural Gas Prices

	1997	1996	1995
NYMEX (US$/mmbtu at Henry Hub Louisiana)	2.48	2.55	1.63
Less: Differential (AECO Hub US$/mmbtu)	(1.14)	(1.53)	(0.79)
	1.34	1.02	0.84
Average Exchange Rate	1.3806	1.3635	1.3725
Alberta Price @ AECO (CDN$/mcf)	1.85	1.39	1.15
Less: NOVA Transportation	(0.13)	(0.12)	(0.12)
Encal Contract/Marketing Premium	0.27	0.43	0.32
Encal Average Alberta Plantgate Price before Hedging Losses	1.99	1.70	1.35
Foreign Exchange Hedging Losses	(0.01)	–	–
Encal Average Alberta Plantgate Price after Hedging Charges (CDN$/mcf)	1.98	1.70	1.35

British Columbia Natural Gas Prices

	1997	1996	1995
NYMEX (US$/mmbtu at Henry Hub Louisiana)	2.48	2.55	1.63
Less: Differential (Sumas US$/mmbtu)	(0.97)	(1.23)	(0.59)
	1.51	1.32	1.04
Average Exchange Rate	1.3806	1.3635	1.3725
British Columbia Price @ Sumas (CDN$/mcf)	2.08	1.80	1.43
Less: Westcoast Energy Transportation	(0.38)	(0.35)	(0.35)
Encal Contract/Marketing Premium (Discount)	0.25	(0.15)	0.25
Encal Average British Columbia Plantgate Price Realization	1.95	1.30	1.33
Less: Westcoast Energy Processing and Gathering *	(0.36)	(0.33)	(0.33)
Encal Average British Columbia Wellhead Price Realization (CDN $/mcf)	1.59	0.97	1.00

* British Columbia has an infrastructure built by Westcoast Energy Inc. that enables gas producers in that province to avoid facility construction in exchange for regulated gathering, processing and transmission fees.

Revenue

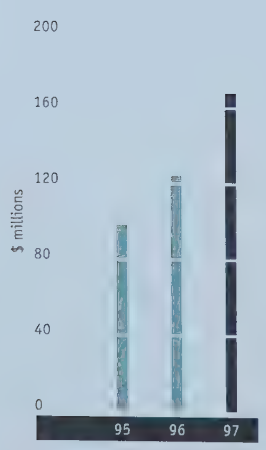
Petroleum and natural gas sales increased 35 percent to $167.8 million in 1997 from $124.3 million in 1996. The increase in sales was the result of a 28 percent increase in oil production and a 23 percent increase in natural gas production from the previous year. Higher natural gas prices also contributed to increased revenue with a 16 percent increase in year over year price after hedging charges.

Revenue

($ thousands)	1997	1996	1995
Crude Oil before Hedging Gains (Losses)	61,366	52,623	40,825
Natural Gas before Hedging Gains (Losses)	89,226	62,282	48,431
Natural Gas Liquids	19,453	13,655	8,306
Crude Oil Hedging Gains (Losses)	(1,244)	(4,732)	292
Foreign Exchange Hedging Losses	(1,534)	(84)	–
Other Revenue	579	550	505
Total	167,846	124,294	98,359

Revenue Impact

($ thousands)	Crude Oil	Natural Gas	NGL	Total
1995 Revenue	40,825	48,431	8,306	97,562
Increase due to Price	10,059	11,564	2,831	24,454
Increase due to Volume	2,037	2,234	2,518	6,789
Increase due to Acquisitions	1,261	279	–	1,540
Decrease due to Dispositions	(1,559)	(226)	–	(1,785)
1996 Revenue	52,623	62,282	13,655	128,560
Increase (decrease) due to Price	(4,420)	10,353	479	6,412
Increase due to Volume	6,428	10,808	5,104	22,340
Increase due to Acquisitions	9,852	9,850	215	19,917
Decrease due to Dispositions	(3,117)	(4,067)	–	(7,184)
1997 Revenue	61,366	89,226	19,453	170,045



Revenue

Expenses

Royalties

Royalties include payments made to the Crown, freehold owners and third parties. Average royalty rates for crude oil and natural gas liquids were 20.6 percent in 1997 compared to 17.5 percent in 1996. Crude oil and natural gas liquids royalties per unit of production increased in 1997 due to higher production rates in the Company's British Columbia properties where oil royalty rates are higher. Average royalty rates for natural gas were 16.7 percent in 1997 compared to 11.7 percent in 1996. Natural gas royalty rates increased during the year due to higher natural gas prices, combined with a reduced influence of Alberta Royalty Tax Credits (ARTC) on the average royalty rate. The 1996 average natural gas royalty rate included prior year adjustments for the over estimation of Crown royalty expense in 1995. The 1998 average royalty rate is forecast to be similar to the 1997 average royalty rate.

Production Expenses

Production expenses for the year increased to $35.1 million from $27.9 million in 1996, a 25 percent increase. This increase is the result of a 26 percent increase in 1997 production compared to 1996. Production expenses per barrel of oil equivalent were down slightly to $4.28 per barrel of oil equivalent in 1997 compared to $4.29 per barrel of oil equivalent in 1996. Per unit production expenses for 1998 are expected to remain consistent with 1997.

Royalties

($ thousands)	1997	1996	1995
Royalties			
Crown (net of ARTC)	25,797	13,439	11,516
Freehold and Other	5,778	5,424	3,455
Net Royalties	31,575	18,863	14,971
Total $/BOE	3.86	2.89	2.42
Average Royalty Rate (%)*	18.6	14.6	15.3
Crude Oil and NGL			
Royalties ($ thousands)	16,658	11,583	8,159
Average Royalty Rate (%)*	20.6	17.5	16.6
Natural Gas			
Royalties ($ thousands)	14,917	7,280	6,812
Average Royalty Rate (%)*	16.7	11.7	13.9

*before hedging losses

Production Expenses

($ thousands)	1997	1996	1995
Total Production Expenses	35,052	27,937	27,561
$/BOE	4.28	4.29	4.46
Crude Oil and NGL			
Production Expenses	14,121	11,882	11,924
$/BOE	4.11	4.49	4.87
Natural Gas			
Production Expenses	20,931	16,055	15,637
$/BOE	4.40	4.15	4.20

Operating Netbacks

	Crude Oil and NGL ($/bbl)			Natural Gas ($/mcf)		
	1997	1996	1995	1997	1996	1995
Price	23.52	25.04	20.07	1.88	1.61	1.30
Crude Oil Hedging Gains (Losses)	(0.36)	(1.79)	0.12	–	–	–
Foreign Exchange Hedging Losses	(0.28)	(0.01)	(0.01)	(0.01)	–	–
Royalties	(4.85)	(4.38)	(3.33)	(0.31)	(0.19)	(0.18)
Production Expenses	(4.11)	(4.49)	(4.87)	(0.44)	(0.41)	(0.42)
Operating Netbacks	13.92	14.37	11.98	1.12	1.01	0.70

General and Administrative Expenses

In 1997, net general and administrative expenses per BOE decreased 15 percent from $1.26 per BOE in 1996 to $1.07 per BOE. Net general and administrative expenses for the fourth quarter were $0.94 per BOE due to higher recoveries from operated capital expenditures and increased production levels. General and administrative expenses in 1998 are anticipated to decrease to approximately $1.00 per BOE.

Financing Charges

Long term debt increased $79.4 million in 1997 to $143.4 million. Long term debt consists of bank debt and senior notes payable. Financing charges increased during 1997 to $7.4 million from $2.3 million in 1996. The increase in 1997 financing charges is largely a result of higher debt levels during 1997 compared to 1996. Financing charges are anticipated to increase in 1998 due to higher average debt levels and increased interest rates.

As at December 31, 1997 the Company has locked in interest rates on CDN$20.0 million of its bank debt at 5.395 percent covering the period January 1998 to March 1999. Encal's US$50.0 million senior notes bear interest at 7.61 percent while the interest rate on the Company's bank debt bears interest at the lender's prime rate or at banker's acceptance rate plus a stamping fee.

General and Administrative Expenses

($ thousands)	1997	1996	1995
General and Administrative	12,358	10,567	9,654
Recoveries	(3,564)	(2,357)	(2,286)
Net General and Administrative	8,794	8,210	7,368
Net General and Administrative ($/BOE)	1.07	1.26	1.19
Recoveries of General and Administrative (%)	29	22	24
Number of Employees and Full Time Consultants (at year end)			
Head Office	116	102	97
Field	28	19	21
Total	144	121	118

Financing Charges

($ thousands)	1997	1996	1995
Interest on Bank Debt	4,416	2,232	2,808
Interest on US Senior Notes	2,565	–	–
Amortization of Deferred Foreign Exchange Losses	94	–	–
Other	294	90	–
Financing Charges	7,369	2,322	2,808
$/BOE	0.90	0.35	0.46

EBIT Interest Coverage

($ thousands)			
EBIT	35,025	23,157	4,137
Financing Charges	7,369	2,322	2,808
EBIT Interest Coverage	4.75	9.97	1.47

EBITDA Interest Coverage

($ thousands)			
EBITDA	92,425	69,284	48,459
Financing Charges	7,369	2,322	2,808
EBIT Interest Coverage	12.54	29.84	17.26

Definitions

EBIT - earnings before income taxes and financing charges

EBITDA - earnings before income taxes, depletion and depreciation and financing charges

Depletion and Depreciation and Site Restoration and Reclamation

Depletion per BOE in 1997 decreased from $7.08 per BOE in 1996 to $7.01 per BOE as a result of lower 1997 proven finding and development costs. The 1997 depletion and depreciation provision increased 25 percent to $55.1 million compared to $43.9 million in 1996 due to increased production.

The Company provided $2.3 million for site restoration and reclamation in 1997 compared to $2.2 million in 1996. This charge amounts to $0.28 per BOE in 1997 and $0.33 per BOE in 1996. In 1997, $0.13 per BOE was incurred and $0.15 per BOE was provided for future site restoration charges. Actual site restoration costs incurred during 1997 and 1996 amounted to approximately $1.0 million in each year.

For purposes of calculating oil equivalence in the depletion calculation, natural gas is converted to a barrel equivalent using six thousand cubic feet equal to one barrel. This conversion factor (6:1) approximates the relative energy value and is commonly used in depletion calculations. The more commonly used financial conversion is 10:1, reflecting relative market values.

Income Taxes

The Company's effective tax rate increased in 1997 to 49 percent from 41 percent in 1996. This increase was due to non-deductible Crown charges that were in excess of allowed resource allowance deductions. Crown royalties, lease rentals and other Crown charges are deducted for accounting purposes but are excluded from the calculation of income for tax purposes. The Income Tax Act, however, permits the deduction of a resource allowance to the extent of 25 percent of resource profits.

As at December 31, 1997 the Company has $12.8 million in non-tax based assets as a result of purchase price discrepancies on corporate acquisitions.

Encal has $340.0 million in resource tax pools available to reduce future taxable income (for more details refer to Note 8 in the 1997 year end audited financial statements). Current income taxes are not expected to be payable for several years due to the Company's large resource pool balances.

Depletion and Depreciation and Site Restoration and Reclamation

($ thousands)		1997	1996	1995
Depletion and Depreciation		55,144	43,951	42,396
Site Restoration and Reclamation		2,256	2,176	1,926
Total		57,400	46,127	44,322
$/BOE	- (Gas to Oil - 10:1)	7.01	7.08	7.17
	- (Gas to Oil - 6:1)	5.05	5.07	5.11
Depletion Rate (%)	- (Gas to Oil - 10:1)	10.40	10.55	11.44
	- (Gas to Oil - 6:1)	10.40	10.36	11.33

Income Taxes Summary

($ thousands)	1997	1996	1995
Deferred Income Taxes	13,600	8,550	1,552
Large Corporation Tax	1,025	767	741
Total	14,625	9,317	2,293
Effective Tax Rate Calculation			
Earnings before Income Taxes	27,656	20,835	1,329
Deferred Income Taxes	13,600	8,550	1,552
Effective Tax Rate (%)	49	41	117

Netback Analysis

($/BOE)	1997	1996	1995
Petroleum and Natural Gas Sales	20.84	19.81	15.87
Hedging Gains (Losses)	(0.34)	(0.74)	0.05
Royalties	(3.86)	(2.89)	(2.42)
Production Expenses	(4.28)	(4.29)	(4.46)
General and Administrative Expenses	(1.07)	(1.26)	(1.19)
Financing Charges	(0.90)	(0.35)	(0.46)
Large Corporation Tax	(0.12)	(0.12)	(0.12)
Funds from Operations	10.27	10.16	7.27
Depletion and Depreciation	(7.01)	(7.08)	(7.17)
Deferred Income Taxes	(1.66)	(1.31)	(0.25)
Amortization of Deferred Foreign Exchange Losses	(0.01)	–	–
Net Earnings (Loss)	1.59	1.77	(0.15)

Capital Expenditures

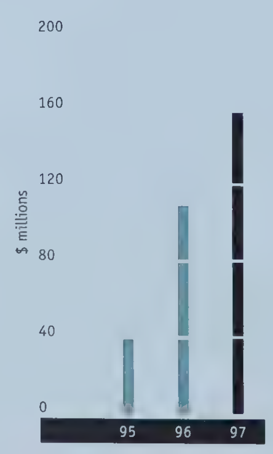
Net capital expenditures in 1997 increased to $157.6 million from $109.3 million in 1996. These expenditures were concentrated in the Company's core regions of British Columbia and West Central Alberta. During 1997 the Company acquired properties for a cost of $56.5 million and sold $40.2 million in properties for a net acquisition and disposition effort of $16.3 million. The major acquisition of 1997 was a package of British Columbia assets acquired in early 1997 for $45.7 million that included interests at Bulrush and Beatton River. A number of smaller transactions account for the balance of the acquisition effort that was aimed at increasing core area dominance in British Columbia and West Central Alberta. Non-core area property dispositions activity was accomplished through the sale of numerous properties in 34 separate transactions.

Since 1995, with a view to consolidating its oil and gas properties, Encal has focused on divesting its non-strategic or uneconomic assets and acquiring producing properties complementary to its existing core regions of British Columbia and West Central Alberta. During the last three years Encal has divested of $73.1 million of non-core properties and has acquired $88.6 million of properties to complement operations. These non-strategic asset disposition and core area acquisition programs are an ongoing process and will continue in 1998.

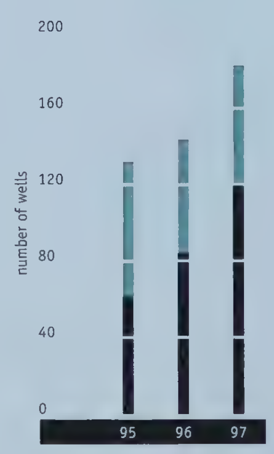
Capital costs associated with miscible fluids relating to the Swan Hills Unit #1 were $1.0 million in 1997 ($1.1 million in 1996). Other capital costs covered office improvements, equipment, computer hardware and software and amounted to $1.5 million in 1997 ($719,000 in 1996).

Capital Expenditures

($ thousands)	1997	1996	1995
Land and Lease	18,013	20,581	7,682
Seismic	8,880	7,339	3,038
Drilling and Completions	72,996	41,129	28,290
Property Acquisitions	56,470	24,645	7,528
Property Dispositions	(40,161)	(12,343)	(20,636)
Total Finding Expenditures	116,198	81,351	25,902
Facilities	38,887	26,071	12,748
Miscible Fluid and Other	2,473	1,858	1,761
Total Finding and Development Expenditures	157,558	109,280	40,411



Capital expenditures



Drilling activity

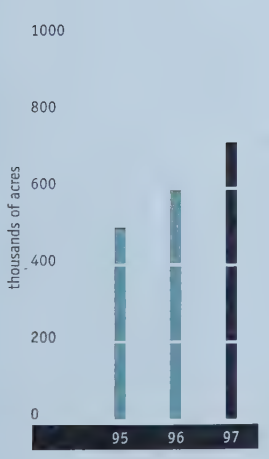
Drilling Results

The Company drilled a total of 181 wells (118.4 net) during 1997 for an overall success rate of 78 percent (74 percent net). The Company's average working interest increased to 65 percent in 1997, compared to 59 percent in 1996 and 45 percent in 1995.

Land

Undeveloped net acres increased by 20 percent in 1997 to 719,470 net acres from 600,502 net acres in 1996. Encal's average working interest in undeveloped acreage increased to 64 percent in 1997 from 53 percent in 1996. Encal invested $15.8 million on undeveloped land, participating selectively at land sales through the year with acquisitions in defined core regions at an average working interest of over 93 percent.

Encal acquired over 115,000 net acres in 1997 at an average acquisition price of $137 per acre. That cost, on average, reflects an increase from prior years due to Encal focusing its activity in competitive areas and the overall strength of the oil and gas industry.



Net undeveloped land

Drilling Results

	1997		1996		1995	
	Gross	Net	Gross	Net	Gross	Net
Natural Gas	66	39.9	54	33.3	50	19.7
Crude Oil	75	47.3	49	24.9	52	21.7
Dry and Abandoned	40	31.2	40	25.5	29	17.9
Total	181	118.4	143	83.7	131	59.3
Success Rate (%)	78	74	72	70	78	70

Drilling Activity

	1997		1996		1995	
	Gross	Net	Gross	Net	Gross	Net
Province						
British Columbia	58	41.9	26	19.1	25	16.1
Alberta	123	76.5	117	64.6	106	43.2
Total	181	118.4	143	83.7	131	59.3

1997 Land Acquisitions

	Gross Acres	Net Acres	Net Dollars	%
Province				
British Columbia	40,755	39,054	5,647,032	36
Alberta	82,079	76,047	10,175,703	64
Total	122,834	115,101	15,822,735	100

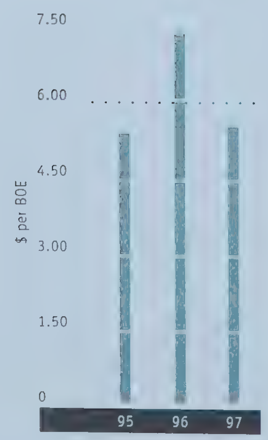
Undeveloped Land

	Gross Acres	Net Acres
December 31, 1995	1,137,573	501,041
Development	(46,080)	(29,064)
Purchases/Additions	252,905	219,478
Expiries/Deletions	(143,149)	(59,875)
Disposals	(68,913)	(31,078)
December 31, 1996	1,132,336	600,502
Development	(61,653)	(22,387)
Purchases/Additions	274,596	229,114
Expiries/Deletions	(88,380)	(40,081)
Disposals	(125,328)	(47,678)
December 31, 1997	1,131,571	719,470

Finding and Development Cost

For 1997, average finding costs were $4.02 per barrel of oil equivalent based on proven plus probable reserves added and $5.11 per barrel of oil equivalent on proven reserves added. Finding and development costs were $5.46 per barrel of oil equivalent on a proven plus probable basis and $6.92 per barrel of oil equivalent on a proven reserves basis.

In calculating finding and development costs, there are often inconsistencies between periods created by the timing of expenditures, particularly related to land purchases and major facility construction, as well as the recognition and revision of reserves. Three year cumulative average calculations are a more meaningful reflection of a company's ability to find and produce reserves effectively.



Finding and development costs (Proven plus probable)
····· three year average

Finding and Development Cost

($ thousands)	Cumulative 1995-1997	1997	1996	1995
Total Finding Expenditures †	223,451	116,198	81,351	25,902
Total Development Expenditures †	83,798	41,360	27,929	14,509
Net Capital Expenditures	307,249	157,558	109,280	40,411
Proven				
Net Reserve Additions (mBOE)*	43,447	22,754	13,927	6,766
Finding Costs ($/BOE)	5.14	5.11	5.84	3.83
Finding and Development Costs ($/BOE)	7.07	6.92	7.85	5.97
Proven Plus 1/2 Probable				
Net Reserve Additions (mBOE)*	47,441	25,815	14,434	7,192
Finding Costs ($/BOE)	4.71	4.50	5.64	3.60
Finding and Development Costs ($/BOE)	6.47	6.10	7.57	5.62
Proven Plus Probable				
Net Reserve Additions (mBOE)*	51,435	28,876	14,941	7,618
Finding Costs ($/BOE)	4.34	4.02	5.44	3.40
Finding and Development Costs ($/BOE)	5.97	5.46	7.31	5.30

† refer to net capital expenditures summary for details

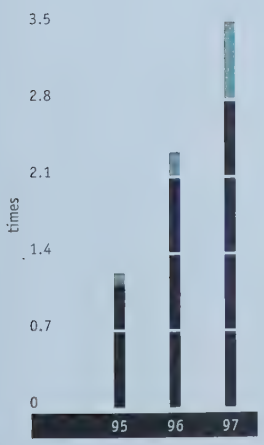
* refer to reserve reconciliation table for details

Reserve Replacement

The Company's 1997 capital investment program replaced 1997 production by a factor of 3.5 times on a proven plus probable basis and 2.8 times on a proven basis, a 52 percent and 33 percent improvement respectively.

Recycle Ratio

The recycle ratio is an often used criteria in evaluating the effectiveness of a company's production and re-investment program. It measures the efficiency of turning a barrel of oil equivalent of production into a new barrel of oil equivalent of reserves. It accomplishes this by measuring the annual cash flow per barrel of oil equivalent netback to that year's proven plus probable finding and development costs.



Reserve replacement ratio
■ Proven ■ Proven plus probable

Reserve Replacement

	1997	1996	1995
Production (mBOE)	8,189	6,516	6,179
Net Proven Reserve Additions (mBOE)	22,754	13,927	6,768
Proven Replacement Ratio	2.8	2.1	1.1
Proven Plus Probable Reserve Additions (mBOE)	28,876	14,941	7,622
Net Proven Plus Probable Replacement Ratio	3.5	2.3	1.2

Recycle Ratio

	1997	1996	1995
Cash Flow Netback ($/BOE)	10.27	10.16	7.27
Proven Finding & Development Costs ($/BOE)	6.92	7.85	5.97
Proven Reinvestment Efficiency Ratio	1.5	1.3	1.2
Proven Plus Probable Finding & Development Costs ($/BOE)	5.46	7.31	5.30
Proven Plus Probable Reinvestment Efficiency Ratio	1.9	1.4	1.4

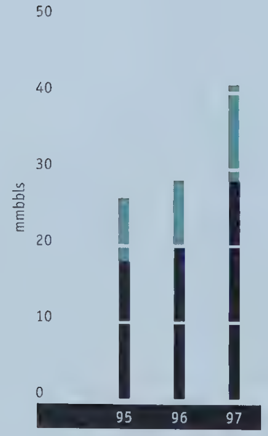
Reserves

The crude oil and natural gas reserves of the Company were evaluated, effective December 31, 1997, by Gilbert Laustsen Jung Associates Ltd., independent petroleum engineering consultants.

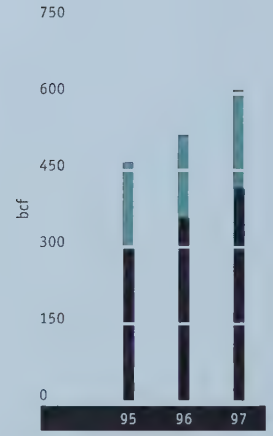
At year end 1997, Encal's proven plus probable crude oil and natural gas liquids reserves increased 43 percent to 40.9 million barrels from 28.7 million barrels in 1996. Proven plus probable natural gas reserves increased 16 percent to 605 billion cubic feet from 520 billion cubic feet in 1996. The Company's reserve life index is 8.3 years for proven and 11.9 years for proven plus probable oil and natural gas liquids reserves and 8.6 years for proven and 12.7 years for proven plus probable natural gas reserves.

Reserve Reconciliation

	Oil and NGL (mbbls)			Natural Gas (bcf)		
	Proven	Probable	Proven plus Probable	Proven	Probable	Proven plus Probable
December 31, 1995	17,516	8,537	26,053	299.54	162.63	462.17
Extensions and Discoveries	3,380	946	4,326	62.02	18.81	80.83
Technical Revisions	700	(776)	(76)	6.90	(16.97)	(10.07)
Acquisitions	1,424	502	1,926	34.12	8.20	42.32
Dispositions	(625)	(277)	(902)	(12.57)	(3.85)	(16.42)
Reserve Additions	4,879	395	5,274	90.47	6.19	96.66
Production	(2,647)	–	(2,647)	(38.69)	–	(38.69)
December 31, 1996	19,748	8,932	28,680	351.32	168.82	520.14
Extensions and Discoveries	9,863	3,343	13,206	107.04	37.33	144.37
Technical Revisions	(44)	(825)	(869)	(5.20)	(7.95)	(13.15)
Acquisitions	3,114	1,227	4,341	26.43	12.02	38.45
Dispositions	(756)	(253)	(1,009)	(22.50)	(15.10)	(37.60)
Reserve Additions	12,177	3,492	15,669	105.77	26.30	132.07
Production	(3,437)	–	(3,437)	(47.52)	–	(47.52)
December 31, 1997	28,488	12,424	40,912	409.57	195.12	604.69



Crude oil and NGL reserves
■ Proven ■ Probable



Natural gas reserves
■ Proven ■ Probable

Reserve Value Reconciliation

The Company's reserve value increased 29 percent to $589.0 million (NPV 15%) at December 31, 1997 compared to $456.0 million at December 31, 1996.

Pricing Forecasts

The unanticipated decrease in crude oil and natural gas prices in the latter part of 1997 did not have a significant impact on the long-term price forecast used by Gilbert Lausten Jung in its independent assessment of Encal's reserves. The volatility of commodity prices is reflected as a short-term anomaly rather than shifting the pricing outlook. A comparison of the price forecast used in the 1997 evaluation with the 1996 evaluation shows that the future trends are virtually identical after 1999 and 2000. As a result, Encal's 1997 reserves were valued at $1 million lower at the end of 1997 compared to the end of 1996 when considering the impact of price forecasts.

Reserve Life Index

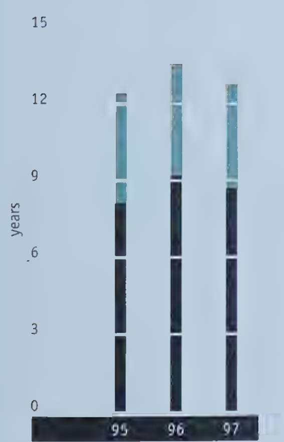
	1997	1996	1995
Crude Oil & NGL			
Production (mbbls)	3,437	2,647	2,448
Proven Reserves (mbbls)	28,488	19,748	17,516
Proven Reserve Life Index (years)	8.3	7.5	7.2
Proven Plus Probable Reserves (mbbls)	40,912	28,680	26,053
Proven Plus Probable Reserve Life Index (years)	11.9	10.9	10.6
Natural Gas			
Production (bcf)	47.5	38.6	37.3
Proven Reserves (bcf)	409.6	351.3	299.5
Proven Reserve Life Index (years)	8.6	9.1	8.0
Proven Plus Probable Reserves (bcf)	604.7	520.1	462.2
Proven Plus Probable Reserve Life Index (years)	12.7	13.5	12.4

Present Value of Reserves

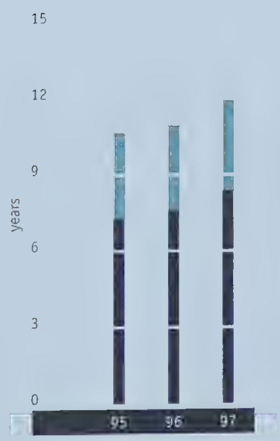
($ million, before income taxes)	1997			1996			1995		
Discount Factor (%)	0	10	15	0	10	15	0	10	15
Proven	994	537	440	732	411	339	544	311	256
Probable	505	202	149	422	160	117	373	146	107
Total	1,499	739	589	1,154	571	456	917	457	363

Reserve Value Reconciliation

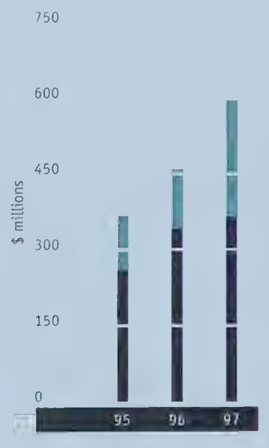
($ thousands, before income taxes)	1997	1996	1995
Opening Reserve Value -			
Proven Plus Probable (NPV 15%)	456,000	363,000	395,000
Net Present Value of Current Year Production	(101,000)	(77,000)	(56,000)
Net Present Value of Current Year Reserve Additions	235,000	186,000	81,000
Change in Value due to Pricing	(1,000)	(16,000)	(57,000)
Closing Reserve Value -			
Proven Plus Probable (NPV 15%)	589,000	456,000	363,000



Reserve life index
Natural Gas
■ Proven ■ Proven Plus Probable



Reserve life index
Crude Oil & NGL
■ Proven ■ Proven Plus Probable



Reserve value (NPV 15%)
■ Proven ■ Proven Plus Probable

Net Reserve Additions

	Proven		Proven plus Probable	
	Oil & NGL	Natural Gas	Oil & NGL	Natural Gas
	(mbbls)	(bcf)	(mbbls)	(bcf)
Province				
British Columbia	7,723	53.9	9,552	72.4
Alberta	4,454	51.9	6,117	59.7
Total	12,177	105.8	15,669	132.1

Reserves

	Oil & NGL (mbbls)			Natural Gas (bcf)		
	Proven	Probable	Proven plus Probable	Proven	Probable	Proven plus Probable
Province						
British Columbia	11,715	4,046	15,761	121	54	175
Alberta	16,773	8,378	25,151	289	141	430
Total	28,488	12,424	40,912	410	195	605

Pricing Assumptions (Gilbert Laustsen Jung Associates Ltd.)

	Crude Oil [1] (US $/bbl)			Crude Oil [2] (CDN $/bbl)			Natural Gas [3] (CDN $/mmbtu)		
Year	1997	1996	1995	1997	1996	1995	1997	1996	1995
1996			17.50			22.75			1.40
1997		21.00	18.00		27.25	23.25		1.70	1.55
1998	19.00	19.00	19.00	25.75	24.75	24.75	1.70	1.75	1.80
1999	20.00	20.00	20.00	26.75	26.00	26.00	1.85	1.85	2.00
2000	20.75	21.00	21.00	27.25	27.25	27.25	2.00	2.00	2.20
2001	21.50	21.50	21.50	28.00	28.00	28.00	2.15	2.25	2.40
2002	22.00	22.00	22.00	28.75	28.75	28.75	2.30	2.35	2.50
2003	22.50	22.50	22.50	29.50	29.50	29.25	2.45	2.50	2.65
2004	23.00	23.00	23.00	30.00	30.00	30.00	2.60	2.60	2.70
2005	23.50	23.50	+2.0%/yr	30.75	30.75	+2.0%/yr	2.70	2.70	+2.0%/yr
2006	24.00	+2.0%/yr		31.25	+2.0%/yr		2.75	+2.0%/yr	
Thereafter	+2.0%/yr			+2.0%/yr			+2.0%/yr		

(1) West Texas Intermediate at Cushing, Oklahoma

(2) Light Sweet at Edmonton, Alberta

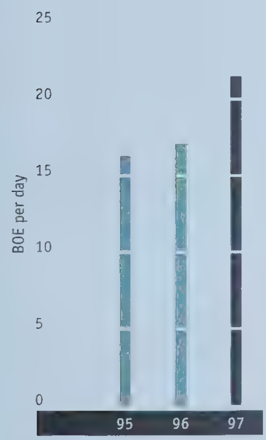
(3) TransCanada Gas Services at NOVA receipt point and 1,000 BTU/SCF

Common Share Information

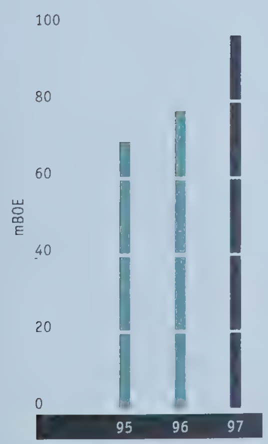
Common Shares issued during 1997 include 792,000 resulting from the exercise of employee stock options. Employee stock options granted to new employees during the year amounted to 976,800. A total of 322,573 options were cancelled during the year. Other than the exercise of employee stock options the Company has not issued new equity since 1993.

Normal Course Issuer Bid

The Company has filed a notice of intention to purchase by way of a Normal Course Issuer Bid certain common shares of the Company. The Company is entitled to purchase up to 10 percent of the 61,921,159 issued and outstanding common shares which make up the public float for the term of the Normal Course Issuer Bid which commenced on January 19, 1998 and will terminate on January 18, 1999.



Production per 100 shares



Reserves per 100 shares
(Proven plus probable)

Common Share Information

(thousands)	1997	1996	1995
Outstanding Shares			
Weighted Average Outstanding Shares			
- Basic	104,421	103,851	103,706
- Fully Diluted	110,334	108,111	106,651
Outstanding Shares December 31			
- Basic	104,784	103,992	103,835
- Fully Diluted	110,577	109,922	108,059

($ thousands except per share amounts)			
Per Share Information			
Net Earnings (Loss)	13,031	11,518	(964)
Net Earnings (Loss) per Share			
- Basic	0.12	0.11	(0.01)
- Fully Diluted	0.12	0.11	(0.01)
Funds from Operations	84,101	66,195	44,910
Funds from Operations per Share			
- Basic	0.81	0.64	0.43
- Fully Diluted	0.77	0.62	0.42
Total Asset Value	513,536	410,141	346,102
Total Asset Value per Share *			
- Basic	4.90	3.94	3.33
- Fully Diluted	4.64	3.73	3.20
Book Value (Shareholders' Equity)	277,454	261,962	249,928
Book Value per Share *			
- Basic	2.65	2.52	2.41
- Fully Diluted	2.51	2.38	2.31
Production (BOE per day)	22,436	17,803	16,928
Production per 100 Shares			
- Basic	21.5	17.1	16.3
- Fully Diluted	20.3	16.5	15.9
Proven plus Probable Reserves (mBOE)	101,381	80,694	72,270
MBOE Reserves per 100 Shares *			
- Basic	96.7	77.6	69.6
- Fully Diluted	91.7	73.4	66.9

* Calculated using outstanding shares at year end

Net Asset Value Per Share

($ thousands)	1997	1996	1995
Reserve Value (15% discount before tax)	589,000	456,000	363,000
Undeveloped Acreage	66,825	50,851	39,000
Seismic and Other Assets	30,000	25,000	20,000
Working Capital Deficiency	(10,409)	(14,961)	(7,269)
Bank Debt	(71,959)	(64,046)	(28,126)
Senior Notes Payable	(71,455)	–	–
Total - Basic	532,002	452,844	386,605
Exercise of Stock Options	20,611	19,797	13,385
Total - Fully Diluted	552,613	472,641	399,990
Net Asset Value per Common Share ($)			
- Basic	5.08	4.35	3.72
- Fully Diluted	5.00	4.30	3.70

Capitalization and Financial Resources

The Company's total capitalization increased 24 percent to $704.3 million during 1997 with the market value of common shares representing 70 percent of total capitalization. Debt including working capital deficiency represented 22 percent of total capitalization. Site restoration and reclamation costs and deferred income taxes accounted for eight percent. The total market value of the Company's common shares increased to $492.5 million largely as a result of share price appreciation. The only common shares issued during 1997 were the result of the exercise of employee stock options.

Financial Resources

Long term debt consists of $71.4 million (US$50 million) senior unsecured notes and $72.0 million of bank borrowing under a $130 million line of credit. At December 31, 1997, the working capital deficiency was $10.4 million compared to $15.0 million at December 31, 1996. During periods of active capital expenditure programs the Company normally operates in a working capital deficiency.

On July 11, 1997 the Company completed a US$50 million private placement of Senior Unsecured Notes. The proceeds were utilized to reduce outstanding bank debt. The Notes carry a 10 year term, bear interest at 7.61 percent and are repayable in equal annual payments of US$10 million commencing on June 30, 2003. This transaction allows the Company to term out a portion of its core debt and is a natural hedge to our US dollar denominated revenue.

Long term debt and working capital deficiency amount to $153.8 million at year end. This total debt level represents approximately 1.8 times 1997 funds from operations of $84.1 million.

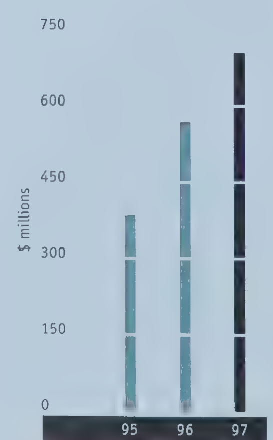
The Company has no material commitments outside of the normal course of business.

Capitalization and Financial Resources

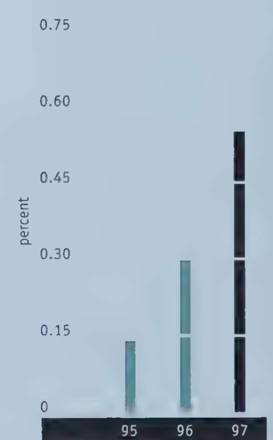
($ thousands except per share amounts)	1997	(%)	1996	(%)	1995	(%)
Common Shares Outstanding (thousands)	104,784		103,992		103,835	
Share Price - ($) December 31 on TSE	4.70		4.29		3.05	
Market Capitalization	492,485	70	446,126	79	316,697	82
Working Capital Deficiency	10,409	1	14,961	3	7,269	2
Bank Debt	71,959	11	64,046	11	28,126	7
Senior Notes Payable	71,455	10	–	–	–	–
Total Debt	153,823	22	79,007	14	35,395	9
Site Restoration and Reclamation	8,233	1	7,021	1	5,888	2
Deferred Income Taxes	49,737	7	36,137	6	27,587	7
Total Capitalization	704,278	100	568,291	100	385,567	100
Total Debt to Total Capitalization	**21.84%**		**13.90%**		**9.18%**	

Key Debt Ratios

($ thousands)	1997	1996	1995
Total Debt to Funds Flow			
Bank Debt	71,959	64,046	28,126
Senior Notes Payable	71,455	–	–
Working Capital Deficiency	10,409	14,961	7,269
Total Debt	153,823	79,007	35,395
Funds from Operations	84,101	66,195	44,910
Years Funds Flow to Repay Total Debt	**1.83**	**1.19**	**0.79**
Asset Coverage Ratio			
Total Assets	513,536	410,141	346,102
Total Debt	153,823	79,007	35,395
Asset Coverage	**3.34**	**5.19**	**9.78**
Total Debt/Equity Ratio			
Total Debt	153,823	79,007	35,395
Shareholders' Equity	277,454	261,962	249,928
Total Debt/Equity	**0.55**	**0.30**	**0.14**



Capitalization



Debt/Equity

Risk Assessment

There are a number of risks facing participants in the Canadian oil and gas industry. Some of the risks are common to all businesses while others are specific to the sector. The following reviews the general and specific risks and includes Encal's approach to managing these risks.

Commodity Risks

Finding

Oil and gas exploration requires the generation of exploration concepts and manpower and capital to test these concepts. The eventual testing of a concept will not necessarily result in the discovery and production of reserves on an economic basis. Encal attempts to minimize finding risk by ensuring that:

- The majority of prospects have multi-zone potential.
- Activity is focused in core regions where expertise and experience is greatest.
- Number of wells drilled is large enough to ensure the continuity of historic success rates.
- Working interests are targeted at over 60 percent in new prospects.
- State-of-the-art geophysical techniques are utilized where appropriate.

Investment Risk Profile

The capital budgeting process is based on risk analysis to ensure capital expenditures balance the objectives of immediate cash flow growth (development activity) and future cash flow from the discovery of reserves (exploration). As a result of this process, evaluation of play types and development of a potential drilling list for 1998, we expect to dedicate 50 percent of the exploration capital budget to plays that will add reserves in 1998 and potentially lead to development activities in 1999 and beyond. Fifty percent will be dedicated to play types that will add to the current year's cash flow.

Production

Beyond exploration risk, there is the potential that the Company's oil and natural gas reserves may not be economically produced at prevailing prices. Encal minimizes this risk where it can by generating exploration prospects internally and attempting to operate the associated project. Operational control allows the Company to control costs, timing, method and sales of production. Production risk is also minimized by concentrating exploration efforts in regions where facilities and infrastructure are Encal-owned, or the Company can control the future development of new facilities and infrastructure.

Price

Crude oil prices are dictated by international supply and demand forces and remain unpredictable. Natural gas prices are influenced by continental supply and demand as well as by transportation access. The Company mitigates price risk in a number of ways:

- Encal's historic oil production is of a high quality and hence not subject to adverse quality differentials.
- Encal's exploration efforts plan on adding high quality light to medium oil reserves.
- Encal concentrates exploration efforts in core regions where expertise levels are highest and more efficient finding and development costs have proven achievable.
- Encal uses financial instruments where appropriate to manage commodity pricing in order to reduce volatility.

Financial and Liquidity Risks

Encal relies on various sources of funding to support its growing capital expenditures program:

- Internally generated cash flow provides the minimum level of funding on which the Company's annual capital expenditures program is based.
- Debt may be utilized to expand capital programs when it is deemed appropriate.
- New equity, if available and if on favorable terms, will be utilized to expand exploration programs.

Cash flow is influenced by factors which the Company cannot control, such as commodity prices, the US/Canadian dollar exchange rate, interest rates and changes to existing government regulations and tax policies. Should circumstances affect cash flow in a detrimental way, Encal would respond by increasing debt to within the Company's self-imposed debt guideline or reducing capital expenditures. The Company uses farm-outs to minimize risk on plays it considers high risk.

Environmental and Safety Risks

There are potential risks to the environment inherent in the business activities of the Company. The Board of Directors has reviewed and approved policies and procedures covering environmental risks, emergency response and employee safety. These policies and procedures are designed to protect and maintain the environment with respect to all corporate operations on behalf of shareholders, employees and the public at large. The Company mitigates environmental and safety risks by maintaining modern facilities, complying with all provincial and federal environmental and safety regulations and maintaining adequate insurance.

During 1996, the Company initiated a three part environmental audit that will see all operated properties audited by the end of 1998. The first two thirds of the operated properties have been audited and no significant issues are outstanding. Work is in progress to rectify all identified deficiencies. In addition to its auditing program, Encal furthered its proactive environmental responsibility through its enrollment in Canada's National Action Plan on Climate Change. In September 1997, Encal submitted an action plan to the Federal Government on the Company's initiatives to reduce total annual greenhouse gas emissions.

The Company has estimated future site restoration and abandonment costs will total $21.7 million and has recognized $2.3 million through increased depletion in 1997. The Company reviews its site restoration and abandonment obligations annually and adjusts its provision based on current costs.

Inflation Risk

Inflation risks subject the Company to potential erosion of product netbacks. Increasing domestic prices for oil and gas production equipment and services can inflate the costs of operating the production.

Supply of Service and Production Equipment

The supply of service and production equipment at competitive prices is critical to the ability to add reserves at a competitive cost and produce these reserves in an economic and timely fashion. In periods of increased activity these services and supplies can become difficult to obtain. The Company attempts to mitigate this risk by developing strong relationships with suppliers and contractors and from time to time will enter into long term service contracts. The company also maintains an appropriate inventory of production equipment.

Risk Management

The objectives of Encal's risk management policy is to secure the capital program and cover debt payments by ensuring that budgeted cash flow levels are attained through the minimization of exposure to commodity price, foreign exchange and interest rate volatility. The objectives are achieved through the use of financial instruments or by negotiating fixed price contracts on the delivery of physical volumes. The program is subject to certain targets and limitations as approved by the Board of Directors from time to time. Effective controls and procedures are in place to ensure that the mandate is followed.

Marketing Risks

Demand for crude oil and natural gas produced by the Company exists within Canada and the United States, however, prices for crude oil are affected by worldwide supply and demand while natural gas liquids and natural gas are limited by North American supply and demand fundamentals.

The Canadian crude oil marketing infrastructure operates efficiently with minimal transportation disruptions affecting the Company. The Company has had little difficulty in marketing all of the oil it can produce given that it accepts the price set by world market supply and demand forces. Company average crude oil quality is high with approximately 56 percent medium crude oil (25° API to 35° API), 41 percent light crude oil (35° API or better) and three percent heavy crude oil (less than 25° API). Higher quality crudes have not been restricted due to pipeline capacity like some of the heavier crudes.

Marketing of Company natural gas production requires longer lead times to arrange transportation and sales contracts. The Company manages this risk by entering into a portfolio of long term contracts and mid term contracts into different geographical regions. Approximately 19 percent of Encal's gas production is sold on a short term basis to backstop deliveries to longer term contracts and to capitalize on short term price increases. Firm sale commitments match production additions from exploration and development success.

Technology Risks

The Company relies on information technology to manage its day to day operations and perform its reporting obligations including the preparation of financial statements, reporting to joint partners and various governments in relation to payment of royalties and taxes.

Year 2000

The Company acquires known technology rather than developing its own technology in relation to business systems. The Company has been in contact with the suppliers of the critical business systems to ensure that they are Year 2000 compliant. Critical business systems include desktop, network and telephone capability, financial reporting and land administration systems. All critical business systems are confirmed to be Year 2000 compliant except for one sub-system that enables the Company to report royalties. An upgrade is required to a new version of the product which is scheduled and budgeted to occur during the latter part of 1998 or early 1999.

The next level of review that has been undertaken is of business systems where failure would not jeopardize the ability of the Company to maintain operation. These would include various engineering and exploration tools. Vendors are being contacted to ensure that these products are compliant. Target date for completion of the contact process is April 30, 1998.

A review of the Company's process control equipment is under way to establish the degree of compliance. Any equipment that is not Year 2000 compliant will be replaced. The collection process is scheduled for completion by March 31, 1998 and initial screening for non-compliance by April 30, 1998.

The Company is canvassing major suppliers and contractors to ensure their ability to continue to support Encal's operations.

Outlook and Prospects for Future Growth

Encal remains confident of its ability for success and future growth. The Company believes it can deliver base growth of 20 percent per year from its internal exploration and development program.

Growth results from the efficient reinvestment of cash flow. Annual cash flow is not only determined by product prices but by production volumes, which are in turn influenced by annual capital expenditure levels. Management has prepared the 1998 Cash Flow Commodity Sensitivities table to assist the reader in understanding the interrelationship of commodity prices and cash flow. The current commodity price environment is sufficient to justify planned exploration and development expenditures, provided efficient finding and development costs and operating costs are maintained.

1998 Capital Budget

The Company has an approved capital budget net of disposals of $160 million for 1998. The Board of Directors reviews the capital budget every quarter and will amend capital spending if required. With a surplus inventory of exploration and development prospects, selectivity will maximize returns.

The 1998 capital budget has been established utilizing commodity price forecasts of US$20.00 WTI per barrel of crude oil and an average of $1.80 per thousand cubic feet for natural gas. The Company's programs are flexible enough that should commodity prices remain at current levels for the balance of 1998, the opportunity capital component of the 1998 capital program can be amended without having a significant impact on 1998 production growth.

1998 Cash Flow Commodity Sensitivities

($ millions)				WTI (US$/bbl)
	17.00	18.00	19.00	20.00
Average Gas Price ($/mcf)				
1.70	83	87	91	95
1.80	88	92	96	100
1.90	92	96	100	105
2.00	97	101	105	109

1998 Sensitivities

($ thousands)	Funds from Operations	Earnings
Change in West Texas Intermediate oil price by US$1.00 per barrel	4,300	2,400
Change in average field price of natural gas by CDN$0.10 per mcf	4,500	2,500
Change in value of CDN dollar compared to US dollar by CDN $0.01	800	450
Change of 1% in prime interest rates	950	525
(above assumes a US dollar exchange rate of $1.3845)		

1998 Capital Budget

($ millions)	
Exploration Capital	90
Development Capital	40
Core Program	130
Opportunity/Discretionary Capital	30
Total Capital	160

management's report

The accompanying financial statements of Encal Energy Ltd. and all the information in this annual report are the responsibility of management and have been approved by the Board of Directors.

The financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the financial statements.

Encal Energy Ltd. maintains systems of internal accounting and administrative controls of high quality, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are appropriately accounted for and adequately safeguarded.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee is appointed by the Board, and all of its members are outside directors. The Committee meets periodically with management, as well as the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each part is properly discharging its responsibilities and to review the annual report, the financial statements and the external auditors' report. The Committee reports its findings to the Board for consideration when approving the financial statements for issuance to the shareholders. The Committee also considers, for review by the Board and approval by the shareholders, the engagement or re-appointment of the external auditors.

The financial statements have been audited by Ernst & Young, the external auditors, in accordance with generally accepted auditing standards on behalf of the shareholders. Ernst & Young has full and free access to the Audit Committee.

Steven A. Allaire
Vice President
Finance and CFO

David D. Johnson
President and CEO

Calgary, Alberta
February 23, 1998

Auditors' Report

To the Shareholders of Encal Energy Ltd.

We have audited the balance sheets of Encal Energy Ltd. as at December 31, 1997 and 1996 and the statements of earnings (loss) and retained earnings and changes in financial position for each of the years in the three year period ended December 31, 1997. These financial statements are the responsibility of the management of the Company. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatements. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1997 and 1996 and the results of its operations and the changes in its financial position for each of the years in the three year period ended December 31, 1997 in accordance with accounting principles generally accepted in Canada.

Ernst & Young

Chartered Accountants

Calgary, Canada
February 23, 1998

auditors' report

Balance Sheets

As at December 31 ($ thousands)	1997	1996
Assets		
Current		
Accounts Receivable	18,366	18,892
Inventory	5,923	2,582
Deposit	–	4,540
	24,289	26,014
Petroleum Property and Equipment *(Note 3)*	486,541	384,127
Deferred Foreign Exchange Losses *(Note 5)*	2,706	–
	513,536	410,141
Liabilities and Shareholders' Equity		
Current		
Accounts Payable	34,698	40,975
Bank Debt *(Note 4)*	71,959	64,046
Senior Notes Payable *(Note 5)*	71,455	–
Site Restoration and Reclamation	8,233	7,021
Deferred Income Taxes	49,737	36,137
	201,384	107,204
Shareholders' Equity		
Share Capital *(Note 6)*	244,509	242,048
Retained Earnings	32,945	19,914
	277,454	261,962
	513,536	410,141

See accompanying notes

On behalf of the Board:

Director

Director

Statements of Earnings (Loss) and Retained Earnings

For the years ended December 31 ($ thousands except per share amounts)	1997	1996	1995
Revenues			
Petroleum and Natural Gas Sales	167,846	124,294	98,359
Royalties	31,575	18,863	14,971
	136,271	105,431	83,388
Expenses			
Production	35,052	27,937	27,561
General and Administrative	8,794	8,210	7,368
Financing Charges	7,369	2,322	2,808
Depletion and Depreciation	57,400	46,127	44,322
	108,615	84,596	82,059
Earnings Before Income Taxes	27,656	20,835	1,329
Income Taxes *(Note 8)*			
Deferred	13,600	8,550	1,552
Large Corporation Tax	1,025	767	741
	14,625	9,317	2,293
Net Earnings (Loss) for the Year	13,031	11,518	(964)
Retained Earnings, Beginning of Year	19,914	8,396	9,360
Retained Earnings, End of Year	32,945	19,914	8,396
Earnings (Loss) Per Share			
Basic	0.12	0.11	(0.01)
Fully diluted	0.12	0.11	(0.01)

See accompanying notes

Statements of Changes in Financial Position

For the years ended December 31 ($ thousands except per share amounts)	1997	1996	1995
Operating Activities			
Net Earnings (Loss) for the Year	13,031	11,518	(964)
Depletion and Depreciation	57,400	46,127	44,322
Deferred Income Taxes	13,600	8,550	1,552
Amortization of Deferred Foreign Exchange Losses *(Note 5)*	70	–	–
Funds from Operations	84,101	66,195	44,910
Change in Non-Cash Working Capital *(Note 2)*	9,893	(616)	(7,183)
	93,994	65,579	37,727
Financing Activities			
Bank Debt	7,913	35,920	2,448
Senior Notes Payable *(Note 5)*	68,679	–	–
Common Shares	2,461	516	444
	79,053	36,436	2,892
Investing Activities			
Petroleum Property and Equipment	(197,719)	(121,623)	(61,047)
Sales of Petroleum Property and Equipment	40,161	12,343	20,636
Site Restoration and Reclamation	(1,044)	(1,043)	(363)
Change in Non-Cash Working Capital *(Note 2)*	(14,445)	8,308	155
	(173,047)	(102,015)	(40,619)
Change in Cash	–	–	–
Funds from Operations Per Share			
Basic	0.81	0.64	0.43
Fully Diluted	0.77	0.62	0.42

See accompanying notes

Notes to Financial Statements
December 31, 1997, 1996 and 1995

notes

1. Significant Accounting Policies

Nature of Business and Basis of Presentation

Encal Energy Ltd. (the Company) operates in the oil and gas industry in Alberta and British Columbia. The financial statements include the accounts of the Company and are stated in Canadian dollars and have been prepared in accordance with accounting principles generally accepted in Canada. The significant accounting policies are summarized below.

Petroleum Property and Equipment

The Company follows the full cost method of accounting for petroleum and natural gas properties. All costs relating to the acquisition of, exploration for and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, lease and well equipment, and overhead expenses related to acquisition and exploration activities. General and administrative expenses are not capitalized other than to the extent of the working interest in Company-operated capital expenditure programs to which operator's fees have been charged pursuant to standard industry operating agreements.

Proceeds from disposal of properties are normally applied as a reduction of the cost of remaining assets without recognition of a gain or loss unless the disposal would result in a change of 20 percent or more in the depletion rate.

The Company applies a ceiling test to capitalized costs to ensure that such costs do not exceed estimated future net revenues from production of proven reserves at year end market prices less future production, general and administrative, financing, site restoration and reclamation, net of salvage values, and income tax costs plus the lower of cost or estimated market value of unproved properties.

Depletion of petroleum and natural gas properties and depreciation of lease and well equipment are calculated using the unit-of-production method based on estimated proven oil and gas reserves. Reserves are converted to common units on the approximate equivalent energy basis.

Site Restoration and Reclamation

The Company provides for the total future liability for site restoration costs on wells and facilities using the unit-of-production method over the estimated life of the oil and gas reserves. The liability is based on estimates of the anticipated method and extent of site restoration, using current costs and in accordance with existing legislation and industry practice. The annual charge of $2,256,000 (1996 - $2,176,000; 1995 - $1,926,000) is grouped with depletion and depreciation expense, with the accumulated provision being shown as a deferred liability. Actual site restoration costs are deducted from the provision in the year incurred.

Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at year end exchange rates. Exchange gains or losses are included in earnings with the exception of the unrealized gains or losses on translation of long term monetary liabilities, which are deferred and amortized over the remaining terms of such liabilities on a straight line basis.

Measurement Uncertainty

The amounts recorded for depletion and depreciation and impairment of petroleum property and equipment and for site restoration and reclamation are based on estimates of reserves and future costs. By their nature, these estimates and those related to the future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

Joint Venture Operations

Substantially all of the exploration and production activities of the Company are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

Per Share Information

Per share information is calculated on the basis of the weighted average number of common shares outstanding during the fiscal year. Fully diluted per share information is calculated on the basis of the weighted average number of common shares that would have been outstanding during the year had all the stock options been exercised at the date of their issuance.

Derivative Financial Instruments

The Company utilizes derivative financial instruments contracts to reduce its exposures to changes in petroleum and natural gas prices, the Canada/US dollar exchange rate and interest rates. Where petroleum and natural gas price swaps based in US dollars are entered into, the Company may use forward foreign exchange contracts to hedge against unfavourable Canada/US dollar exchange rates. Gains and losses incurred on these contracts are recognized in income concurrently with the hedged transaction. In the case of interest rate swaps, the differential to be paid or received is accrued as interest rates change and is recognized over the term of the agreements. The fair values of these contracts are not reflected in the financial statements.

Income Taxes

The Company follows the tax allocation method of accounting for income taxes. Under this method, deferred income taxes are recorded to the extent that income taxes otherwise payable are reduced by capital cost allowances and exploration and development costs in excess of the depletion and depreciation provisions recorded in the accounts.

2. Changes in Non-Cash Working Capital

($ thousands)	1997	1996	1995
Cash provided by (Used for):			
Accounts Receivable	526	3,898	(512)
Inventory	(3,341)	1,932	668
Deposit	4,540	(4,540)	–
Accounts Payable	(6,277)	6,402	(7,184)
Changes in Non-Cash Working Capital	(4,552)	7,692	(7,028)

These changes relate to the following activities:			
Operating Activities	9,893	(616)	(7,183)
Investing Activities	(14,445)	8,308	155
	(4,552)	7,692	(7,028)

3. Petroleum Property and Equipment

($ thousands)	1997	1996
Petroleum Property and Equipment	675,919	518,361
Accumulated Depletion and Depreciation	(189,378)	(134,234)
	486,541	384,127

Included in petroleum property and equipment is the amount of $66,825,000 (1996 - $50,851,000) representing the cost of undeveloped lands for which no depletion has been provided.

4. Bank Debt

The Company has an unsecured $100.0 million term credit facility and a $30.0 million operating credit facility from Canadian chartered banks of which $72.0 million was outstanding under the term credit facility at December 31, 1997 (1996 - $64.0 million). The interest rate on outstanding debt varies but approximates the lenders' prime rate (1997 - 4.77%; 1996 - 6.17%). The Company has the option (subject to bank approval) of converting it's term credit facility to a reducing credit facility in whole or in part. Payments under the reducing facility would be required on a semi-annual basis in order that the facility be repaid by the maturity date of December 31, 2002. The facility provides for various interest rate and Bankers Acceptance fee options, which are based on market rates in effect from time-to-time. Financial covenants include the maintenance of tangible net worth of at least $200.0 million, minimum annual cash flow from operations before interest expense greater than two times interest expense, maximum long term debt not to exceed borrowing base limit of $200.0 million and a debt to equity ratio no greater than 1:1. The Company is in compliance with all of these covenants. The Company has an interest rate swap outstanding at December 31, 1997 (Note 7).

5. Senior Notes Payable

On July 11, 1997, the Company issued US$50.0 million of 7.61% senior unsecured notes with a ten year term maturing July 11, 2007. The notes are repayable in five equal installments of US$10.0 million beginning July 11, 2003 with interest payable semi annually in arrears until maturity. The debt ranks equally with the Company's other debt obligations and is subject to certain financial covenants. The aggregate deferred foreign exchange loss arising upon translation of the notes at the year end rate was $2.7 million net of accumulated amortization.

6. Share Capital

Authorized

Unlimited number of Class A preferred shares issuable in series

Unlimited number of Class B preferred shares issuable in series

Unlimited number of common shares at no par value

Issued and Outstanding Common Shares

Issued and Outstanding Common Shares

($ thousands except share amounts)	Number	Value
Balance at December 31, 1994	103,458,120	241,088
Issued Pursuant to the Exercise of Stock Options	376,639	444
Balance at December 31, 1995	103,834,759	241,532
Issued Pursuant to the Exercise of Stock Options	157,564	516
Balance at December 31, 1996	103,992,323	242,048
Issued Pursuant to the Exercise of Stock Options	791,838	2,461
Balance at December 31, 1997	104,784,161	244,509

As at December 31, 1997, the number of weighted average shares outstanding (basic) is 104,420,793 (1996 - 103,851,000; 1995 - 103,706,000).

Stock Options

Under the terms of the stock option plan, options to purchase common shares may be granted to management, employees and directors at an exercise price and exercise period as determined by the Board of Directors. All outstanding options were granted for a five year term. At December 31, 1997, options to purchase 5,792,604 common shares were outstanding at prices ranging from $2.66 to $5.35 per share and expiring between 1998 and 2002.

Included in the outstanding option amount are 1,625,000 incentive options; 1,400,000 of which were granted to the Company's executive officers on December 6, 1996 at an exercise price of $3.65 and 225,000 granted to an executive officer on March 24, 1997 at an exercise price of $4.10. The options become exercisable as to 33.33% on the market price of the Corporation's common shares reaching $5.74, being reflective of a 12% compound annual growth rate over four years from the date of grant and as to 66.67% on the market price of the Corporation's common shares reaching $6.38, being reflective of a 15% compound annual growth rate over four years from the date of grant.

Activity in the plan through December 31, 1997 was as follows:

Options Outstanding

	Number of Shares	Price Per Share	Total Price
Balance at December 31, 1994	3,093,600	0.32 - 5.88	$ 10,539,150
Options Granted	1,876,700	2.66 - 3.30	5,187,990
Options Cancelled	(462,668)	2.38 - 5.88	(2,182,620)
Options Exercised	(283,332)	0.32 - 2.38	(159,330)
Balance at December 31, 1995	4,224,300	2.38 - 4.60	$ 13,385,190
Options Granted	2,311,250	2.80 - 4.00	8,342,320
Options Cancelled	(447,918)	2.66 - 3.55	(1,414,446)
Options Exercised	(157,564)	2.38 - 3.55	(515,655)
Balance at December 31, 1996	5,930,068	2.38 - 4.60	$ 19,797,409
Options Granted	976,800	4.10 - 5.35	4,332,520
Options Cancelled	(322,573)	2.66 - 5.10	(1,057,335)
Options Exercised	(791,691)	2.38 - 3.65	(2,461,164)
Balance at December 31, 1997	5,792,604	2.66 - 5.35	$ 20,611,430

As at December 31, 1997, the Company has reserved 3,638,057 common shares for future issuance under the plan.

7. Financial Instruments

The Company's financial instruments recognized in the balance sheet consist of accounts receivable, accounts payable, bank debt and senior notes payable. The fair value of these financial instruments approximates their carrying amounts. The Company's petroleum and natural gas sales include a charge of $2,778,000 (1996 - $4,816,000 charge; 1995 - $292,000 gain) and interest expense includes a charge of $647,000 (1996 - $324,000 charge; 1995 - nil), as a result of hedging activities.

The Company is a party to certain off-balance sheet derivative financial instruments, including crude oil, natural gas, foreign exchange and interest rate swap contracts. The Company enters into these contracts for hedging purposes only, in order to protect its future Canadian dollar earnings

and funds from operations from the volatility of crude oil and natural gas commodity prices, US/Canadian dollar exchange rates and interest rates. The swap contracts reduce fluctuations in petroleum and natural gas sales and financing charges respectively, by locking in fixed Canadian dollar prices on a portion of its petroleum and natural gas sales and locking in fixed interest rates on a portion of its floating rate debt.

Contracts outstanding in respect to financial instruments were as follows:

($ millions except where otherwise stated)	Contract Amounts Quantity	Average Fixed Price/Rate $Canadian	Hedge Period
As at December 31, 1997			
Crude Oil Swaps	20,000 barrels per month	US$20.73	Dec 98
	10,000 barrels per month	US$20.00 - 21.20*	Dec 98
US Dollar Swaps	US$93	1.3734	Dec 98
Interest Rate Swaps	CDN$20	5.395%	Mar 99
As at December 31, 1996			
Crude Oil Swaps	26,667 barrels per month	25.00 - 26.13	Mar 97
	20,000 barrels per month	25.00 - 26.13	Dec 97
	20,000 barrels per month	26.25 - 29.95**	Dec 97
US Dollar Swaps	US$29	1.3375	Dec 97
	US$24	1.3348	Dec 98
Interest Rate Swaps	CDN$20	6.27%	Jan 98
As at December 31, 1995			
Crude Oil Swaps	40,000 barrels per month	22.97 - 23.75	Dec 96
Interest Rate Swaps	CDN$10	7.0%	Jan 97

* costless collar with minimum floor of US$20.00 and maximum ceiling of US$21.20

**costless collar with minimum floor of $26.25 and maximum ceiling of $29.95

On settlement, these contracts result in cash receipts to or payments by the Company for the difference between the fixed contract and floating market rates for the applicable dollars and volumes hedged during the contract term. Such cash receipts or payments offset corresponding decreases or increases in the Company's petroleum and natural gas sales or interest expense.

At December 31, the estimated fair values on the above swap transactions were as follows:

($ thousands receivable (payable))	1997	1996
Crude Oil Swaps	1,066	2,181
US Dollar Swaps	(4,437)	(442)
Interest Rate Swaps	(61)	(539)

The above estimated fair values are based on the market value of these financial instruments as at year end and represent the amounts the Company would receive or pay to terminate the contracts at year end. These instruments' have no book values recorded in the financial statements.

The Company may be exposed to certain losses in the event of non-performance by counterparties to these contracts. The Company mitigates this risk by entering into transactions with major international financial institutions with appropriate credit ratings and ensuring that this credit risk is not concentrated with a small number of counterparties.

8. Income Taxes

The actual income tax provision differs from the expected amount calculated by applying the Canadian combined federal and provincial corporate income tax rate to earnings before income taxes. The major components of these differences are explained as follows:

($ thousands)	1997	1996	1995
Earnings Before Income Taxes	27,656	20,835	1,329
Canadian Statutory Rate	44.78%	44.73%	44.57%
Expected Income Tax Expense	12,384	9,319	592
Increase (Decrease) in Income Taxes Resulting From:			
Non-deductible Royalties and Payments	12,720	7,172	6,330
Non-deductible Portion of Depletion	663	707	869
Alberta Royalty Tax Credit	(544)	(656)	(675)
Resource Allowance	(11,637)	(7,909)	(5,551)
Other	14	(83)	(13)
Deferred Income Tax Expense	13,600	8,550	1,552

The Corporation has the following deductions at December 31, 1997 available for future income tax purposes:

($ thousands)		Maximum Annual Rate of Claim
Canadian Exploration Expense	75,000	100%
Canadian Development Expense	58,000	30%
Canadian Oil and Gas Property Expense	126,000	10%
Undepreciated Capital Cost	81,000	20-30%
	340,000	

Approximately $24.0 million of the Company's tax pools are successored due to the change of control resulting from corporate acquisitions and may only be claimed against future net production revenues from the acquired properties.

9. United States Accounting Principles and US Dollar Summary Information

The Company's financial statements have been prepared in accordance with generally accepted accounting principles in Canada ("Canadian GAAP"). These principles, as they pertain to the Company's financial statements, differ from United States' generally accepted accounting principles ("US GAAP") as follows:

The application of US GAAP would have the following effects on earnings as reported:

(CDN $ thousands for years ended December 31)	1997	1996	1995
Net Earnings (Loss) - Canadian GAAP	13,031	11,518	(964)
Deferred Foreign Exchange Losses	(2,706)	-	-
Depletion and Depreciation	5,853	6,533	8,057
Deferred Income Taxes	196	(2,619)	(2,893)
Foreign Exchange Forward Contracts	(4,437)	(442)	(31)
	(1,094)	3,472	5,133
Net Earnings - US GAAP	11,937	14,990	4,169
Earnings Per Share - US GAAP (Basic and Fully Diluted)	0.11	0.14	0.04

The application of US GAAP would have the following effects on the balance sheets as reported:

(CDN$ thousands at December 31)	1997 Canadian GAAP	1997 US GAAP	1996 Canadian GAAP	1996 US GAAP
Petroleum Property and Equipment	486,541	436,126	384,127	327,605
Deferred Foreign Exchange Losses	2,706	–	–	–
Deferred Income Taxes	49,737	35,296	36,137	21,196
Retained Earnings (Deficit)	32,945	(10,172)	19,914	(22,109)

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In accordance with US GAAP, unrealized gains or losses arising on translation of long term liabilities repayable in foreign funds would be included in earnings in the period in which they arise. See Note 1 for Canadian GAAP treatment.

In accordance with US GAAP, the discounted future net cash flows from proven reserves, discounted at 10 percent over the remaining productive life, plus the lower of cost or estimated fair market value of unproved properties, net of future taxes, must exceed the net book value to such properties, net of deferred taxes and estimated site restoration, or a write down is required. Under Canadian GAAP, the ceiling test calculation is computed on an undiscounted basis. At December 31, 1997, 1996 and 1995, the conditions of these ceiling tests under Canadian GAAP and US GAAP were met.

In accordance with US GAAP, the liability method of accounting for income taxes is used instead of the deferral method required under Canadian GAAP. Under the liability method, deferred tax assets and liabilities are recorded on differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities, and are measured using the enacted tax rates that are assumed will be in effect when the differences reverse. The effect on deferred taxes of a tax rate change is recognized in the statement of earnings (loss) for the period covering the enactment date. See Note 1 for Canadian GAAP treatment.

Under US GAAP, the liability method of accounting for income taxes and the ceiling test calculation in years prior to 1995 resulted in differences in the carrying values of petroleum property and equipment, deferred income taxes liability, depletion and depreciation, and deferred income taxes expense.

In accordance with US GAAP, foreign exchange forward contracts associated with anticipated future transactions are recognized in the financial statements at fair value, with any resulting gain or loss immediately reflected in income. Under Canadian GAAP, these contracts are accounted for as a hedge of the anticipated future transactions. Accordingly, gains and losses arising on the contracts are deferred and recognized in income in the period in which the underlying transactions are recognized.

Summary Financial Information in US Dollars

The following information is based on US GAAP and translated from Canadian into US dollars at the average exchange rates for each of the years presented.

(US$ thousands except per share amounts)	Year ended December 31 1997	1996	1995
Petroleum and Natural Gas Sales	120,849	90,735	71,802
Funds from Operations	60,553	48,322	32,784
Per Share - Basic	0.58	0.47	0.32
Per Share - Fully Diluted	0.57	0.46	0.32
Net Earnings	8,595	10,943	3,043
Per Share - Basic	0.08	0.10	0.03
Per Share - Fully Diluted	0.08	0.10	0.03
Average Exchange Rate (CDN$)	0.72	0.73	0.73

1997

Selected Quarterly Information

Financial Highlights

1997

($ thousands except per share amounts)	Three Months Ended 1997 March 31	June 30	Sept. 30	Dec. 31	Annual 1997
Income Statement					
Petroleum and Natural Gas Sales	46,159	36,329	37,697	47,661	167,846
Funds from Operations	25,212	17,814	17,378	23,697	84,101
Per Share - Basic	0.24	0.17	0.17	0.23	0.81
Per Share - Fully Diluted	0.23	0.16	0.16	0.22	0.77
Net Earnings	6,112	1,989	1,369	3,561	13,031
Per Share - Basic	0.06	0.02	0.01	0.03	0.12
Per Share - Fully Diluted	0.06	0.02	0.01	0.03	0.12
Balance Sheet					
Capital Spending					
Land and Lease	6,505	3,998	6,423	1,087	18,013
Seismic	5,779	1,321	627	1,153	8,880
Drilling and Completions	20,305	4,859	22,037	25,795	72,996
Facilities	12,392	8,031	8,138	10,326	38,887
Property Dispositions	(5,413)	(6,861)	(14,336)	(13,551)	(40,161)
Property Acquisitions	47,087	4,819	3,794	770	56,470
Miscible Fluid and Other	749	966	540	218	2,473
	87,404	17,133	27,223	25,798	157,558
Total Debt					
Bank Debt	117,187	130,388	64,238	71,959	
Senior Notes Payable	–	–	69,100	71,455	
Working Capital Deficiency	23,760	9,493	15,537	10,409	
	140,947	139,881	148,875	153,823	
Total Shareholders' Equity	268,814	271,364	273,715	277,454	

(thousands)				
Share Information				
Shares Outstanding at End of Period				
- Basic	104,219	104,395	104,721	104,784
- Fully Diluted	109,940	110,267	110,450	110,577
Weighted Average Shares Outstanding for the Period				
- Basic	104,102	104,318	104,498	104,757
- Fully Diluted	109,883	110,275	110,499	110,565
Volume Traded During Quarter - TSE	8,576	4,562	6,519	8,588
Volume Traded During Quarter - NYSE	–	31	363	406
Controlled by Management and Directors (%)	40	40	40	41
Public Float (%)	60	60	60	59
Share Price ($) -TSE				
- High	4.40	4.95	5.75	5.75
- Low	3.90	3.95	4.00	4.40
- Close	4.00	4.75	5.35	4.70
Equity Market Capitalization At Closing Price ($)	416,876	495,876	560,257	492,485

1997
Selected Quarterly Information
Operational Highlights

	Three Months Ended 1997				Annual
	March 31	June 30	Sept. 30	Dec. 31	1997
Production					
Natural Gas (mcf/d)	130,606	123,226	128,910	137,981	130,197
Crude Oil (bbls/d)	6,217	6,156	7,145	8,180	6,931
Natural Gas Liquids (bbls/d)	2,188	2,659	2,226	2,877	2,485
Total (BOE/d)	21,466	21,138	22,262	24,855	22,436
Pricing					
Natural Gas ($/mcf) (before hedging losses)	2.22	1.64	1.60	2.02	1.88
Foreign Exchange Hedging Losses ($/mcf)	–	(0.01)	(0.01)	(0.02)	(0.01)
Natural Gas ($/mcf) (after hedging losses)	2.22	1.63	1.59	2.00	1.87
Crude Oil ($/bbl) (before hedging losses)	27.68	23.98	22.97	23.14	24.25
Crude Oil Hedging Losses ($/bbl)	(1.85)	(0.05)	(0.07)	(0.16)	(0.49)
Foreign Exchange Hedging Losses ($/bbl)	(0.02)	(0.59)	(0.40)	(0.51)	(0.38)
Crude Oil (after hedging losses) ($/bbl)	25.81	23.34	22.50	22.47	23.38
Natural Gas Liquids ($/bbl)	27.03	19.47	19.99	20.12	21.45
Royalties, net of ARTC ($/BOE)	4.58	3.46	3.30	4.07	3.86
Operating Costs ($/BOE)	4.37	4.20	4.32	4.23	4.28
Netbacks ($/BOE)	14.95	11.23	10.78	12.55	12.36
General and Administrative ($/BOE)	1.10	1.13	1.15	0.94	1.07
Depletion and Depreciation ($/BOE)	7.09	7.15	7.06	6.78	7.01
Drilling Results (Gross Wells)					
Natural Gas	34	–	11	21	66
Crude Oil	11	9	14	41	75
Dry	22	1	13	4	40
Total Drilled	67	10	38	66	181
Drilling Results (Net Wells)					
Natural Gas	20.0	–	8.6	11.3	39.9
Crude Oil	3.3	6.2	11.5	26.3	47.3
Dry	16.8	0.1	10.5	3.8	31.2
Total Drilled	40.1	6.3	30.6	41.4	118.4
Success Rate (%)	58	98	66	91	74

1996
Selected Quarterly Information
Financial Highlights

1996

($ thousands except per share amounts)	March 31	June 30	Sept. 30	Dec. 31	Annual 1996
	Three Months Ended 1996				
Income Statement					
Petroleum and Natural Gas Sales	27,714	29,061	29,200	38,319	124,294
Funds from Operations	15,080	16,022	14,560	20,533	66,195
Per Share - Basic	0.15	0.15	0.14	0.20	0.64
Per Share - Fully Diluted	0.14	0.15	0.14	0.19	0.62
Net Earnings	2,278	2,319	1,366	5,555	11,518
Per Share - Basic	0.02	0.02	0.02	0.05	0.11
Per Share - Fully Diluted	0.02	0.02	0.02	0.05	0.11
Balance Sheet					
Capital Spending					
Land and Lease	2,701	4,994	3,594	9,292	20,581
Seismic	1,681	2,136	1,624	1,898	7,339
Drilling and Completions	9,350	4,278	13,216	14,285	41,129
Facilities	6,086	5,846	4,960	9,179	26,071
Property Dispositions	(1,976)	(1,064)	(4,398)	(4,905)	(12,343)
Property Acquisitions	515	1,141	9,128	13,861	24,645
Miscible Fluid and Other	641	523	332	362	1,858
	18,998	17,854	28,456	43,972	109,280
Total Debt					
Long Term Debt	26,305	30,314	41,261	64,046	
Working Capital Deficiency	13,065	10,946	14,437	14,961	
	39,370	41,260	55,698	79,007	
Total Shareholders' Equity	252,206	254,525	255,891	261,962	

(thousands)				
Share Information				
Shares Outstanding at End of Period				
- Basic	103,835	103,835	103,835	103,992
- Fully Diluted	108,084	108,045	107,986	109,922
Weighted Average Shares Outstanding for the Period				
- Basic	103,835	103,835	103,835	103,900
- Fully Diluted	108,048	108,053	107,986	108,359
Volume Traded During Quarter	3,701	6,516	7,021	26,355
Controlled by Management and Directors	44%	44%	41%	40%
Public Float	56%	56%	59%	60%
Share Price ($)				
- High	3.10	3.25	3.65	4.40
- Low	2.65	2.75	2.75	3.20
- Close	2.92	2.85	3.40	4.29
Equity Market Capitalization At Closing Price ($)	303,000	296,000	353,000	446,126

1996
Selected Quarterly Information
Operational Highlights

($ thousands except per share amounts)	Three Months Ended 1996 March 31	June 30	Sept. 30	Dec. 31	Annual 1996
Production					
Natural Gas (mcf/d)	90,817	102,347	109,185	120,306	105,713
Crude Oil (bbls/d)	5,680	5,331	5,271	5,447	5,432
Natural Gas Liquids (bbls/d)	1,477	1,795	1,858	2,068	1,800
Total (BOE/d)	16,239	17,361	18,048	19,546	17,803
Pricing					
Natural Gas ($/mcf)	1.68	1.49	1.38	1.86	1.61
Crude Oil ($/bbl) (before hedging losses)	22.77	26.15	27.44	29.41	26.47
Crude Oil Hedging Losses ($/bbl)	(0.87)	(2.25)	(2.82)	(3.66)	(2.38)
Foreign Exchange Hedging Losses ($/bbl)	(0.01)	(0.01)	(0.02)	–	(0.01)
Crude oil (after hedging losses) ($/bbl)	21.89	23.89	24.60	25.75	24.08
Natural Gas Liquids ($/bbl)	17.33	20.21	19.06	25.05	20.72
Royalties, net of ARTC ($/BOE)	2.43	2.37	2.84	3.79	2.89
Operating Costs ($/BOE)	4.40	4.12	4.33	4.29	4.29
Netbacks ($/BOE)	11.93	11.89	10.42	13.23	11.89
General and Administrative ($/BOE)	1.28	1.37	1.27	1.13	1.26
Depletion and Depreciation ($/BOE)	7.06	7.14	6.98	7.12	7.08
Drilling Results (Gross Wells)					
Natural Gas	15	3	17	19	54
Crude Oil	11	11	12	15	49
Dry	7	5	9	19	40
Total Drilled	33	19	38	53	143
Drilling Results (Net Wells)					
Natural Gas	9.1	1.2	9.8	13.2	33.3
Crude Oil	3.6	2.2	7.8	11.3	24.9
Dry	3.5	2.7	6.1	13.2	25.5
Total Drilled	16.2	6.1	23.7	37.7	83.7
Success Rate (%)	78	56	74	65	70

Historical Review

history

Year ended December 31 ($ thousands except per share data)	1997	1996	1995	1994	1993	1992	1991
Financial							
Petroleum and Natural Gas Sales	167,846	124,294	98,359	82,870	47,981	6,386	5,052
Funds from Operations	84,101	66,195	44,910	41,483	24,719	3,247	1,804
Per Share - Basic	0.81	0.64	0.43	0.51	0.59	0.16	0.09
Per Share - Fully Diluted	0.77	0.62	0.42	0.50	0.51	0.12	0.09
Net Earnings (Loss)	13,031	11,518	(964)	4,480	4,757	880	156
Per Share - Basic	0.12	0.11	(0.01)	0.06	0.11	0.04	0.00
Per Share - Fully Diluted	0.12	0.11	(0.01)	0.06	0.10	0.03	0.00
Net Capital Expenditures	157,558	109,280	40,411	198,305	130,961	5,480	1,263
Total Assets	513,536	410,141	346,102	348,243	147,027	18,979	14,097
Working Capital (Deficiency)	(10,409)	(14,961)	(7,269)	(14,297)	(2,584)	(1,793)	(794)
Long Term Debt	143,414	64,046	28,126	25,678	5,560	5,792	7,791
Shareholders' Equity	277,454	261,962	249,928	250,448	121,084	8,950	4,151
Weighted Average Common Shares (Fully Diluted, thousands)	110,334	108,111	106,651	83,911	61,654	26,917	20,635
Operating							
Production							
Natural Gas (mmcf)	47,522	38,691	37,303	27,851	18,156	3,060	2,729
Daily (mcf)	130,197	105,713	102,201	76,303	49,744	8,360	746
Average Price ($/mcf)	1.87	1.61	1.30	1.84	1.75	1.61	1.34
Crude Oil and NGL (mbbls)	3,437	2,647	2,448	1,708	951	76	75
Daily (bbls)	9,416	7,232	6,708	4,680	2,605	208	205
Average Price ($/bbl)	22.87	23.24	20.19	18.36	17.02	18.95	18.68
Proven plus Probable Reserves							
Natural Gas (bcf)	604.7	520.1	462.2	477.5	256.3	52.3	45.4
Crude Oil and NGL (mbbls)	40,912	28,680	26,053	23,077	12,497	1,521	1,340
Present Value ($ thousands discounted at 15% before income taxes)	589,000	456,000	363,000	395,500	236,289	47,892	38,145
Undeveloped Land							
Gross Acres (thousands)	1,132	1,132	1,138	1,463	1,133	60	44
Net Acres (thousands)	719	601	501	639	423	20	13

Shareholder Information

Registrar and Transfer Agent

CIBC Mellon Trust Company
600, 333 - 7th Avenue S.W.
Calgary, Alberta
T2P 2Z1
Phone: (403) 232-2400
Fax: (403) 264-2100
E-Mail: inquires@cibcmellon.ca
Website: www.cibcmellon.ca
Answerline: 1-800-387-0825

Chase Mellon Shareholder Services
New York, New York

Stock Exchange Listing

The Toronto Stock Exchange
Symbol: ENL
New York Stock Exchange
Symbol: ECA

Shareholder Contacts

Shareholders are welcome to contact the Company for information or questions concerning their shares. For general information about the Company, contact Mrs. Karen Ruzicki or Mr. Steven Allaire at (403) 750-3300.

For information on such matters as share transfers and change of address inquiries, contact the Transfer Agent. The address and telephone number of the transfer agent are listed on this page.

Annual Information Form

Copies of the Annual Information Form are available to shareholders upon request.

French Material

Copies of the Information Circular, Notice of the Annual General Meeting, Proxy, Management Discussion and Analysis and Financial Statements are available in french.

Dividend Policy

The Company does not pay dividends as cash flow is utilized to support current operations, exploration and development programs and to fund acquisitions of oil and gas properties.

Annual Meeting

The Annual General Meeting of Shareholders will be held on Wednesday, May 6, 1998 at 3:00 p.m. in the McMurray Room, Calgary Petroleum Club
Calgary, Alberta

Estimated Release Dates of Quarterly Results

First Quarter	April 28, 1998
Second Quarter	July 29, 1998
Third Quarter	October 28, 1998

Corporate Governance

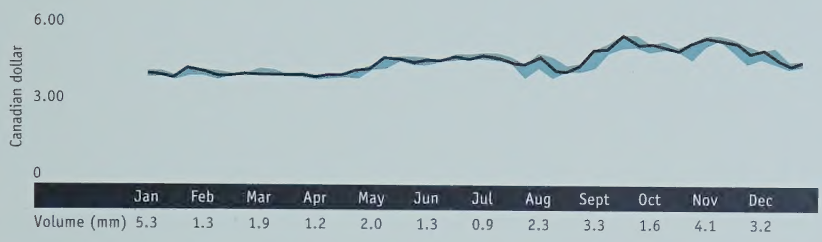
A system of corporate governance for the Corporation has been established to provide the Board of Directors, management and shareholders of the Corporation with effective governance. A more detailed discussion of corporate governance is available in the Information Circular for the Annual and Special General Meeting of Shareholders.

Internet

Encal is on the internet. Look for our home page for access to recent press releases, quarterly reports and annual report information at Web Site: **http://www.encal.com**

Share Information

1997 Toronto Stock Exchange Volume & Trading Price Range



1997 New York Stock Exchange Volume & Trading Price Range

Common Shares	
Outstanding December 31, 1997	
Basic	104,784,000
Fully Diluted	110,577,000
Weighted Average December 31, 1997	
Basic	104,421,000
Fully Diluted	110,334,000
Closing Price of Shares	
December 31, 1997	$4.70
Market Capitalization (using December 31, 1997 closing price)	$492,485,000
Controlled by management and the Board of Directors	40%
Public Float	60%
Major Shareholders TMI - FW Inc.	30,074,139
Share Trading Information	
Volume of Shares Traded during 1997	
TSE	28,530,849
NYSE	854,500

Corporate Information

Directors

Thomas M. Taylor*
Chairman
Encal Energy Ltd.
Taylor & Co.
Fort Worth, Texas

David D. Johnson
President and CEO
Encal Energy Ltd.
Calgary, Alberta

Robert G. Jennings†
President
Jennings Capital Inc.
Calgary, Alberta

Harold P. Milavsky† *
Chairman
Quantico Capital Corp.
Calgary, Alberta

Byron J. Seaman†
Private Investor
Calgary, Alberta

Daryl K. Seaman*
President
Dox Investments Ltd.
Calgary, Alberta

**Members of Compensation Committee*
†Members of Audit Committee

Officers

David D. Johnson
President and CEO

Steven A. Allaire
Vice President, Finance and CFO

Terrence R. Barrows
Vice President, Production

Peter A. Carwardine
Vice President, Land and Corporate Development

Michael R. Culbert
Vice President, Marketing

James D. Reimer
Vice President, Exploration

Arthur A. MacNichol
Controller

Gordon M. Adams
Secretary

Management

Robert S. Attwood
Manager, Information Technology

William V. Bradley
Manager, Corporate Development

Greg W. Chury
Manager, Land

Glenn A. Downey
Manager, Exploration

Kathy L. Howell
Manager, Financial Reporting

Gerri M. Murphy
Manager, Land Administration

Robert R. Padget
Manager, Engineering

David K. Saul
Manager, Operational Accounting

Gordon B. Vogt
Manager, Joint Operations

Tim J. Wollen
Manager, Production

Corporate Offices

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Bankers

Bank of Nova Scotia
Corporate and Energy Banking
3820, 700 - 2 Street S.W.
Calgary, Alberta
T2P 2N7

Royal Bank of Canada
Oil and Gas Banking Centre
1100, 335 - 8 Avenue S.W.
Calgary, Alberta
T2P 1C9

Solicitors

Parlee McLaws
3400 PetroCanada Centre
150 - 6th Avenue S.W.
Calgary, Alberta
T2P 3Y7

Auditors

Ernst & Young
1300 Ernst & Young House
707 - 7th Avenue S.W.
Calgary, Alberta
T2P 3H6

Consulting Engineers

Gilbert Laustsen Jung Associates Ltd.
4100, 400 - 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2

Field Offices

4705 - 42nd Street
Stettler, Alberta
T0C 2L0
Phone: (403) 742-4448
Fax: (403) 742-1210

10716 - 101 Street
Fort St. John, British Columbia
V1J 2B9
Phone: (250) 787-7974
Fax: (250) 787-7987

For Your Reference

Abbreviations

AECO	- Alberta Energy Company (reference price for natural gas)
API	- American Petroleum Institute
ARTC	- Alberta Royalty Tax Credit
Bbls	- barrels
Bbls/d	- barrels per day
Bcf	- billions of cubic feet
BOE	- barrels of oil equivalent
Bopd	- barrels of oil per day
Btu	- British Thermal Unit
CDN	- Canadian
Condensate	- A mixture of pentane and heavier hydrocarbon that is gaseous in its reservoir state, but which condenses to a liquid at atmospheric pressure and temperature
Mbbls	- thousands of barrels
MBOE	- thousands of barrels of oil equivalent
Mcf	- thousands of cubic feet
Mcf/d	- thousands of cubic feet per day
Miscible fluids	- Injection of hydrocarbon fluids into a reservoir to enhance the recovery of oil
Mmcf	- millions of cubic feet
Mmcf/d	- millions of cubic feet per day
US	- United States
WTI	- West Texas Intermediate, oil price reference set at Cushing, Oklahoma

Glossary

Metric Conversion Table

The Canadian Petroleum industry uses the International System of Units for measuring and reporting. The following table notes conversion factors relevant to this report.

To convert from	To	Multiply by
Thousand cubic feet	Thousand cubic metres	0.028169
Barrels	Cubic Metres	0.159000
Feet	Metres	0.305000
Miles	Kilometres	1.609000
Acres	Hectares	0.405000

Table Index

Graph Index

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